Integrated Offshore Transmission Project (East)

Appendix 1

Technology Work-Stream Report

Appendix 1 – Technology Work-Stream

1. Introduction

This appendix reports on currently available technologies and technologies which may become available within project timescales to enable an integrated offshore transmission system be built. It reports on the limitations of current technology development and identifies where technology development needs to be focussed in the future to allow the successful delivery of an integrated network.

The technologies considered in the report are those relevant to the potential system design options for the integrated offshore transmission network, including HVDC converters and their protection and control systems, switchgear, d.c. and a.c. cables and offshore platforms.

The report is structured into a number of separate chapters:

Chapter 2 provides an introduction to the technologies that might be used in an integrated offshore transmission network and highlights issues related to their application.

Chapter 3 considers the commercial availability of the key technologies. It establishes the present state of development and forecasts future developments. It aims to provide an indication of whether technology will be available for application within the timescales of a given project.

Chapter 4 provides high level unit costs for each of the technology areas to inform cost benefit analyses and optioneering. In each case, a range of costs is given to reflect the complexity factors associated with different projects. The sources of information and the assumptions made in deriving the unit costs are stated.

Chapter 5 describes how VSC HVDC schemes may be constructed in stages to better match investment with system requirements where the need for a higher transmission capacity at some point in the future is anticipated. The chapter introduces VSC HVDC transmission configurations and describes how a scheme may be constructed in stages.

Chapter 6 provides information on reliability and availability for key technology areas to further support cost benefit analyses.

Chapter 7 is concerned with protection strategies for an integrated offshore transmission network. Possible protection strategies are illustrated using a set of generic scenarios, representing the different basic types of connection that might be used in an integrated network.

Chapter 8 is concerned with strategies for the control of power flows in an integrated offshore transmission network. Potential control strategies are illustrated using the same set of generic scenarios as in the previous chapter. The particular nature of the offshore a.c. 'islands' is taken into account. The characteristics of offshore windfarms relevant to their connection to an integrated network are described in Annex A to the chapter.

Chapter 9 draws conclusions from the previous chapters and highlights areas where technology development is required in order to allow an integrated offshore transmission network to be delivered.

2. Technology areas

2.1 Introduction

This chapter introduces the technologies that might be used in an integrated offshore transmission network and highlights issues related to their application. The material presented provides the necessary background for the chapters that follow.

2.2 Technologies for integrated offshore transmission

For the purposes of the present chapter, the technologies for integrated offshore transmission have been grouped under the headings ‘HVDC converters, ‘switchgear’, ‘cables’ and ‘offshore platforms’.

2.2.1 HVDC converters

The majority of HVDC schemes currently in service use line commutated converter (LCC) technology (also know as current sourced converter or ‘classic’ HVDC), which has been commercially available since 1954. LCC HVDC transmission has been described in detail by a number of authors, examples being works by Arrillaga [1] and Kundur [2]. The main characteristics of LCC HVDC technology that are relevant to its application in an integrated offshore transmission system are summarised below.

LCC HVDC technology uses thyristor valves to control the commutation of current between the converter and the three phases of the a.c. system in turn. A thyristor is switched on by the application of a pulse to its gate terminal and will switch off when the current attempts to change direction. It cannot be switched off by control action. As a consequence, the converter is dependent on an a.c. voltage source for its operation. Furthermore, the strength of the a.c. system, as characterised by the ratio of a.c. short circuit level relative to the d.c. power, is important for stable operation. Guidance on the interaction phenomena that may occur between a.c. and d.c. systems where the a.c. system is weak is given in [3], while guidance on planning and design to take the interaction phenomena into account is considered in [4].

Since the thyristor valves of an LCC HVDC converter can be switched on by control action but not switched off, commutation of the current between the phases of the a.c. system can be delayed with respect to the a.c. system voltage but cannot be advanced. LCC HVDC converter operation is therefore accompanied by reactive power absorption, typically in the range 50 to 60% of the transmitted power. The converter is provided with reactive compensation plant in the form of switched capacitor banks. The capacitor banks are switched in or out to maintain the reactive power exchange within specified limits as the transmitted power is varied. Dynamic reactive compensation and shunt reactors are also required in some applications.

The commutation of an essentially d.c. current between the phases of the a.c. system gives rise to harmonic distortion. Some or all of the capacitor banks provided for reactive compensation are therefore configured to also provide a.c. harmonic filtering in order to keep the harmonic distortion on the a.c. system within permitted levels.

The space required for reactive compensation plant and a.c. harmonic filters in a LCC HVDC converter station may typically account for 50% or more of the station footprint.

A LCC HVDC converter operating as an inverter is susceptible to faults and disturbances in the a.c. system which may cause commutation failure. A commutation failure acts as a short-circuit of the converter bridge on which it occurs, resulting in temporary interruption to the power transmission. The causes and consequences of commutation failure are discussed in [5]. When the inverters of more than one HVDC system are in electrical proximity, a single fault or disturbance in the a.c. system may cause simultaneous commutation failures and loss of transmission in all links. Furthermore, commutation failure at one inverter might itself cause an a.c. system disturbance that induces commutation failure at other inverters that would otherwise not have been affected. Guidance on systems with multiple inverters in electrical proximity is given in [6].

LCC HVDC technology is able to achieve high power ratings, an example being an HVDC link connecting Jinping and Sunan in China with a power rating of 7200 MW operating at ± 800 kV d.c. which was commissioned in 2013. The d.c. current corresponding to the power rating and operating voltage is approximately 4.5 kA. Typical losses for a LCC HVDC converter are around 0.8% of the transmitted power. LCC HVDC converters are not able to operate continuously at low levels of power, typically less than 5 to 10% of the rated power transmission capacity. Power reversal is accompanied by a change in the polarity of the d.c. voltage, which precludes use of LCC HVDC technology with extruded cables.

Data on the reliability of HVDC systems throughout the world is collected annually by CIGRE Advisory Group B4.04 [7]. The data is reported in accordance with a reporting protocol developed by the Advisory Group [8]. A standardised reporting protocol for operational performance data for LCC HVDC systems is defined in PD IEC/TS 62672-1 [9].

Voltage sourced converter (VSC) HVDC transmission is a relatively new technology. It was first applied commercially in 1997 [10] and significant growth in application and development in the technology have occurred since then. Guidance on VSC HVDC power transmission is given in BSI PD IEC TR 62543 [11]. The characteristics of VSC HVDC transmission that are relevant to its application in an integrated offshore transmission network are summarised below.

The valves of a VSC HVDC converter are self-commutated, that is they use semiconductor devices that can be switched both on and off, as required, by control action. The usual semiconductor device is the insulated gate bipolar transistor (IGBT). The valves generate a power frequency a.c. voltage at the a.c. terminals of the converter. Since it acts as a voltage source, the VSC is not dependent on a strong a.c. network. It can be used with weak and passive systems and, where required, provide black start capability.

The a.c. terminal voltage is controlled in phase angle and amplitude to give the required exchange of active and reactive power, respectively, between the converter and the a.c. system. Active and reactive power are controlled independently and both may be controlled rapidly and continuously within the limits of the converter's rating. The present generation of VSC HVDC converters requires little or no a.c. harmonic filtering.

Since a VSC HVDC converter requires little or no reactive compensation and a.c. harmonic filters, the station footprint is less than that of an equivalent LCC HVDC converter. A comparison of the site area required for VSC HVDC and LCC HVDC converter stations both of 500 MW rating was reported in [12]. A VSC HVDC solution required a site area of 58% of that of the LCC solution. The building footprint, however, was larger on account of the larger size of the valves.

A VSC HVDC converter may continue to transmit power in the event of a fault on the a.c. system, albeit at a reduced level depending on the reduction of a.c. system voltage. VSC HVDC converters do not suffer commutation failures.

Although the earlier VSC HVDC systems were of quite modest power transfer capacity, developments in converter technology have resulted in continuously increasing capabilities. The highest rated VSC HVDC system in service at present is the 500 MW East–West Interconnector between Ireland and Wales [13]. A number of VSC HVDC systems with higher power transmission capacities are under construction at present, including some at 1000 MW [14, 15].

Much development has been aimed at reducing VSC HVDC converter losses. Losses for the present generation of VSC HVDC converters are less than 1% of the transmitted power per converter.

Power reversal is accompanied by a reversal of the d.c. current, with the d.c. voltage polarity remaining unchanged. Continuous operation at any level of power within its rating is possible. Since no reversal of the d.c. voltage polarity occurs, VSC HVDC converters may be used with extruded cables.

Little information on reliability and availability of VSC HVDC converters has been published, reflecting the still comparatively limited service experience. However, there is no reason to expect that the reliability of VSC HVDC systems will be found to be any lower than that of LCC HVDC systems.

Published values for VSC HVDC converter stations tend to show costs in the range 100 – 120% of the equivalent LCC HVDC converter station. National Grid's 2013 Electricity Ten Year Statement (ETYS) states the cost of a 1250 MW VSC HVDC converter to be in the range £108–136 M [16]. The economic aspects relating to the application of VSC links within a transmission system are discussed in CIGRE Ref. 492 [17].

The differences between VSC and LCC HVDC technology may lead to one or the other being better suited to the functional requirements of a given project. VSC HVDC technology tends to be advantageous in the following situations:

- where short circuit levels are low or where a black start capability is required
- where rapid control of power or rapid power reversal is required
- where the use of extruded cables is required
- where limited space is available

LCC HVDC technology tends to be advantageous where a power transfer capability is required that exceeds that achievable with VSC technology. For cabled applications, however, this advantage is becoming less relevant as increasing VSC ratings approach the power transfer capability of the cables. In applications where none of the factors that favour the use of VSC technology are important to a project, LCC technology may provide a more economic solution.

The application of HVDC links in the Integrated Offshore Transmission Project is primarily for connection of wind generation located offshore, together with reinforcement of the onshore transmission network. Some of the HVDC links are likely to be multi-terminal.

The use of HVDC transmission for connection of wind generation is described in CIGRE Ref. 370 [18]. VSC technology is well suited to such connections. Since the converter does not require a commutating voltage from the a.c. system and since it is able to operate at any level of power flow within its rating, the VSC HVDC system can be used to start up the wind farm and provide auxiliary power to the wind farm during periods of no wind generation. An LCC HVDC connection would require a synchronous condenser or Statcom to provide a commutating voltage and a generator to provide auxiliary power during periods of no wind generation. The inability of the LCC HVDC system to operate continuously at levels of power less than 5 to 10% of its rated level would be a disadvantage for energisation of the wind farm and operation at low wind speeds. The VSC HVDC converter is more compact than an equivalent LCC converter and can be accommodated on an offshore platform with less difficulty. In consequence, the use of LCC technology for wind generation and offshore applications would generally require significant additional investment compared to a VSC solution and would present some additional engineering challenges.

While most of the HVDC schemes in service comprise a d.c. connection between two terminals, in some applications, a multi-terminal link is found to represent a cost-effective and efficient solution. For example, a multi-terminal HVDC link could be used to combine offshore wind generation connection with onshore reinforcement such that spare capacity on the link could be used for cross-boundary power transfer during periods when the wind generation is less than 100%.

LCC technology can be used for multi-terminal HVDC systems. However, since reversal of the power flow direction requires a change in the polarity of the d.c. voltage, reversal of power flow at individual terminals requires switching to reconfigure the d.c. circuit. In addition, commutation failures can occur, resulting in collapse of the d.c. voltage and interrupting operation of the whole multi-terminal HVDC system.

At present, two multi-terminal LCC HVDC systems are in service: The SACOI (Sardinia – Corsica – Italy) project, commissioned in 1989, and the Quebec – New England HVDC transmission system which was commissioned in phases between 1990 and 1992. Both of these are LCC HVDC systems.

The SACOI HVDC system was originally commissioned as a two-terminal system connecting Sardinia and the Italian mainland. A third converter station, at Lucciana on the island of Corsica, was connected as a tap in 1988. The original two-terminal system was designed for unidirectional power flow from Sardinia to Italy. The Lucciana Converter station was provided with d.c. switchgear to allow a bidirectional flow of power to and from Corsica.

The first phase of the Quebec – New England HVDC project was a two-terminal system between Des Cantons, in Quebec, and Comerford in New Hampshire. It was originally planned to extend the existing system north to Radisson in Quebec and south to Sandy Pond in Massachusetts and to adapt the controls at Des Cantons and Comerford for multi-terminal operation. Finally, a converter station was to be commissioned at Nicolet, in Quebec, to form a five-terminal system. In the course of the project the scope was changed resulting in a system that can be operated as a three-terminal system (Radisson – Nicolet - Sandy Pond) or as two separate two-terminal systems (Radisson – Nicolet and Des Cantons - Comerford). A description of the HVDC transmission system is given in [19].

A third multi-terminal LCC HVDC system, the North East Agra HVDC project, is planned [20]. The HVDC link will comprise rectifiers at Bishwanath Chariali and Alipurduar and two parallel inverters at Agra. The power flow will be unidirectional and no reversal of d.c. voltage polarity will be necessary.

In principle, VSC technology is better suited to multi-terminal HVDC links than LCC technology. Since power flow reversal does not involve a change in the polarity of the d.c. voltage, the power flow can be reversed at individual terminals without reconfiguring the d.c. circuit. Also, VSC HVDC converters do not suffer commutation failures.

The first two multi-terminal VSC HVDC schemes have recently entered service. A three-terminal VSC HVDC system was commissioned at Nan'ao in China in December 2013 [21]. The system connects wind generation located on Nan'ao island to the transmission system in Guangdong. A five-terminal system was commissioned in Zhoushan in China in June 2014 [22]. The system reinforces the connection between the islands of Zhoushan and the mainland transmission system.

A disadvantage of multi-terminal HVDC systems is that, until the advent of a HVDC circuit-breaker, a d.c. fault will result in loss of transmission at all terminals of the HVDC system while the faulted part is isolated and the system restarted. This disadvantage would limit the quantity of generation that can be connected to the HVDC system to that permitted by infeed loss risk limits of the planning standards unless some form of partial redundancy is provided. A further disadvantage is the lack of standards for control and protection that would ensure that the equipment of different suppliers could operate on a common HVDC system. Progress is being made in this area by working bodies within CIGRE and CENELEC.

International standards have been developed against which HVDC equipment and systems may be procured. HVDC schemes in general tend to be of bespoke design in order to achieve an optimum solution for a particular application. The design of the system is strongly influenced by the a.c. system characteristics at each terminal, with factors such system strength and harmonic impedances being important considerations. The requirements for component equipment items are determined from design calculations.

General guidance on performance requirements for two-terminal LCC HVDC systems is provided in BS EN 60919 [23, 24, 25]. The report comprises three parts: BS EN 60919-1 concerns the steady state performance, BS EN 60919-2 concerns the transient performance related to faults and switching and BS EN 60919-3 concerns the dynamic performance. Guidance on VSC for HVDC power transmission is given in BSI PD IEC TR 62543 [11]. The report aims to provide a guide for specifying a VSC transmission scheme.

Guidance on procedures for insulation coordination of HVDC converter stations, where they differ from a.c. system practice, is provided in IEC TS 60071-5 [26]. The guide is primarily concerned with LCC HVDC systems.

Electrical type and production tests for converter valves are specified in BS EN 60700-1 [27] for LCC and in BS EN 62501 [28] for VSC HVDC transmission.

Tests for VSC converter components including valves, interface transformer, d.c. capacitor, sub-module capacitors, reactors and radio frequency interference filters are proposed in CIGRE technical brochure 447 [29].

Standard procedures for determining power losses for LCC HVDC converter stations are presented in BS EN 61803 [30]. The procedures cover all components of the converter station but do not include any dynamic reactive compensation plant that may be used. General principles for calculating power losses for VSC HVDC converter valves are set out in IEC 62751-1 [31]. IEC 62751-2 [32] provides the detailed method to be used for calculating power losses in VSC HVDC converter valves based on the modular multilevel converter (MMC) topology.

Guidance on system tests for two-terminal LCC HVDC installations is given in BS EN 61975 [33]. The standard provides guidance on planning of commissioning activities. Guidelines for commissioning of VSC HVDC schemes are being developed by CIGRE WG B4.63.

Guidance on technical specifications for and design evaluation of a.c. harmonic filters for HVDC systems is given in PD IEC TR 62001-1 [34]. Part 1 constitutes an overview. Part 4, which will address equipment, is being developed within IEC SC 22F.

Specification and evaluation of outdoor audible noise from HVDC substations is specified in PD IEC/TS 61973 [35]. The specification is primarily intended for LCC HVDC projects. Part of it may be used for VSC HVDC projects.

A number of projects are in progress within IEC TC 115, including control and protection equipment in HVDC systems, guidelines for HVDC system operation procedures, guidelines on asset management of HVDC installations, planning of HVDC systems and guidelines for the system design of HVDC projects.

The requirements for converter transformers for HVDC applications are specified in BS EN 61378-2 [36]. Requirements for bushings used on d.c. systems are specified in BS EN 62199 [37].

2.2.2. Switchgear

AC switchgear for transmission applications is a mature and widely used technology. The requirements are well covered in international standards. Common specifications for a.c. switchgear are specified in BS EN 62271-1 [38], requirements for a.c. circuit-breakers are specified in BS EN 62271-100 [39] and requirements for a.c. disconnectors and earthing switches are specified in BS EN 62271-102 [40]. The requirements for synthetic testing of circuit-breakers are specified in BS EN 62271-101 [41] and requirements for inductive load switching in BS EN 62271-110 [42].

In a HVDC system, switching operations that differ from those specified in the standards are encountered. BS EN 60919-2 classifies switching operations without faults as follows:

a) energization and de-energization of a.c. side equipment such as converter transformers, a.c. filters, shunt reactors, capacitor banks, a.c. lines, static var compensators (SVC) and synchronous compensators;

b) load rejection;

c) starting and removal from service of converter units;

d) operation of d.c. breakers and d.c. switches for paralleling of poles and lines; connection or disconnection of d.c. lines (poles), earth electrode lines, metallic return paths, d.c. filters, etc.

Switchgear requirements corresponding to the above switching operations in addition to the various fault switching duties for the HVDC system are determined from the design calculations.

Gas-insulated metal enclosed switchgear (GIS) is used in a.c. systems as an alternative to conventional air-insulated switchgear in certain applications, often on account of its compact size or greater immunity to airborne pollution. GIS is therefore widely used for a.c. switchgear in offshore applications. Requirements for GIS are specified in BS EN 62271-203 [43]. The standard completes and amends, if necessary, the standards applying to the component switchgear items of the GIS.

DC switchgear is not covered by its own specific standards. Many of the requirements of the a.c. switchgear standards will be applicable to d.c. switchgear. In contrast, switching duties will generally be different for d.c. equipment and the equipment will need to withstand a continuous d.c. voltage. The functions and operation of switching devices, other than circuit-breakers, that are used in d.c. applications have been described in a report by CIGRE WG 13/14.08 [44, 45]. The report was published in two parts, with Part 1 covering current commutation switches and Part 2 covering disconnectors and earthing switches. An earlier report, by WG 13.03, deals with the metallic return transfer breaker (MRTB), which is used for reconfiguring a bi-polar system for mono-polar operation [46]. Guidance on the specification of d.c. switchgear is given in BS EN 60919-2.

GIS is not widely used for d.c. applications. Under the influence of a d.c. electric field, charge may accumulate on the surfaces of solid insulators within the gaseous insulation system. Accumulation of charge distorts the electric field profile and may reduce the performance of the insulation. However, should a solution to the issue be found, GIS would offer an attractive solution for HVDC converters located offshore. Gas insulated systems for HVDC are summarised in [47].

So far, circuit-breakers have not been applied in HVDC systems. The availability of a HVDC circuit-breaker would allow a d.c. network to develop beyond a single protection zone for earth faults. This in turn would enable the volume of generation connected to a d.c. network to exceed the maximum loss of power infeed permitted by planning standards.

The performance requirements of a circuit-breaker for d.c. application are significantly more onerous than for a.c. application. The circuit-breaker must interrupt a current that has no natural current zero. Furthermore, since a d.c. fault will cause a voltage collapse that propagates rapidly throughout the d.c. network, the circuit-breaker must operate within a few ms. In principle, these requirements could be fulfilled using a semiconductor circuit-breaker, but the associated losses have prevented such a device from being developed.

A hybrid HVDC circuit-breaker has been demonstrated in the laboratory [48]. The device uses a small auxiliary circuit-breaker to bypass the main semiconductor circuit-breaker during normal operation and hence reduce the losses. In the event of a fault, the auxiliary circuit-breaker trips to commutate the fault current into the path of the main circuit-breaker. A high speed mechanical switch protects the auxiliary breaker from exposure to high recovery voltages as the main circuit-breaker interrupts the fault.

Due to the fast operating time, novel protection concepts are required. In the case of the device described above, operation is initiated by built-in overcurrent protection. The device may then operate in a current limiting mode, delaying operation of the main circuit-breaker, until a trip signal from selective protection is received.

2.2.3. Cables

Two main types of cable technology have been developed for use in HVDC applications. These are distinguished by the type of insulation, mass impregnated (MI) and extruded. Both types of cable consist of a copper or aluminium conductor surrounded by the insulation, a metallic sheath to protect the cable and prevent moisture ingress and a plastic outer coating. Cables for subsea installation are additionally provided with armouring in the form of helically wound galvanised steel wires to increase the tensile strength of the cable and protect it from the stresses associated with subsea installation. For installation in deeper waters, a double layer of armouring is provided. The armouring may be covered with a serving of bitumen-impregnated polypropylene yarn for corrosion protection.

Extruded d.c. cable systems have been in service since 1999. The insulation is cross-linked polyethylene (XLPE), which is extruded over the cable core. The ratings of extruded cables have continued to increase since their introduction. At present, a number of projects using extruded cables with a d.c. voltage of 320 kV and power transfer capabilities of up to 1000 MW are under construction and a 525 kV d.c. extruded cable system has been qualified. Extruded cables have not been used with LCC HVDC systems due to the need to withstand the d.c. voltage polarity reversal that occurs when the power flow direction is changed.

MI cables have been in service since the 1950s and have demonstrated high reliability. The insulation consists of lapped layers of kraft paper which are impregnated with viscous oil. A recent development from MI insulation is polypropylene laminated (PPL) insulation, in which the kraft paper is laminated with thin layers of plastic. PPL insulation permits a higher operating temperature and hence allows a higher current rating for the cable to be achieved. MI cables generally have higher ratings than extruded cables. The highest d.c. voltage for MI cables currently on order is 600 kV, providing a continuous power transfer capability of 2250 MW. MI cables can be used with both VSC and LCC HVDC systems.

Recommendations for testing of d.c. cables with rated voltages of up to 800 kV have been published in [49] and an addendum published in [50]. Recommendations for testing of d.c. extruded cable systems with rated voltages of up to 500 kV have been published in [51].

Three-core a.c. subsea cables have been widely used for connection of offshore wind generation. The cable consists of three copper conductor cores, each surrounded by XLPE insulation and a lead sheath, laid up into a single cable with oversheath and helically-wound steel wire armouring. Constructing the cable with the three cores in close proximity significantly reduces the external magnetic field and consequent losses due to induced currents. Three-core a.c. submarine cables are available for rated voltages of 245 kV.

Single-core a.c. cables have not been widely used for subsea application. On land, special sheath bonding may be used to balance the voltages induced along the sheaths of single core cables and thereby reduce circulating currents and their associated losses. Since special bonding is not practical for subsea cables, low resistance copper armouring has been used as an alternative. The cable cost, however, is significantly increased due to the larger quantity of copper used.

Nominal cross sectional areas for conductors in electric power cables are specified in BS EN 60228 [52]. Test methods and requirements for power cables with extruded insulation and their accessories for rated voltages 30 kV to 150 kV are specified in IEC 60840 [53]. The requirements apply to single-core and individually screened three-core cables. Test methods and requirements for power cables with extruded insulation and their accessories for rated voltages from 150 kV to 500 kV are specified in IEC 62067 [54]. The requirements apply to single core cables and their accessories. The requirements of the latter two standards do not apply to submarine cables, for which modifications to the standard tests may need to be devised.

A critical differentiating factor between the use of a.c. and d.c. cables is the influence of capacitive charging current. At power frequency, for lengths of more than a few km, the charging current may account for a significant proportion of the cable current rating. The active power that can be transmitted decreases sharply with cable length. The impact of the charging current is greater at higher voltages. The charging current can be compensated for by the provision of shunt reactors. However, for subsea cables, it will only be practical to install shunt reactors at the ends of the circuit and the use of cables for a.c. transmission over long distances remains impractical. Many of the wind generation areas in the Crown Estate Round 3 zones are located such that HVDC cables are the only practical option for connection to the onshore transmission system.

Installation of submarine cables is a challenging operation which may represent a significant part of the cost of an offshore project. The cost is strongly influenced by sea bed conditions and the presence of obstacles. A detailed sea bed survey and selection of an appropriate route are essential.

Cables are installed from a dedicated cable laying vessel or, in shallow waters, from a barge. The maximum length of cable that can be laid and hence the number of cable joints to be made along the cable route is determined by the capacity of the laying vessel. Making the cable joints is a skilled operation requiring a period of around three days of good weather so that the vessel may remain stationary while the joint is made.

The stresses imposed on a submarine cable during installation are a significant factor in the cable design. Recommendations for mechanical tests on submarine cables have been published in [55]. Detailed stress analyses using computer models are also performed.

Submarine cables are buried in the sea bed to protect them from damage from ships anchors and fishing equipment. For this purpose, a trench is cut by water jet or cable plough depending on the sea bed conditions. In difficult sea bed conditions burial may not be possible and the cable is instead protected using concrete mattresses, rock placement or other means. Guidance on protection of cables from third-party damage is given in [56].

The cables of a circuit may be bundled and buried in a single trench or spaced apart and buried in separate trenches. Burial of the cables in a single trench will reduce the costs of installation but will also limit the achievable rating due to mutual heating. It will also be more difficult to carry out a repair, should one be required, once the cables are in service. In the case of d.c. cables, restrictions on the allowable compass deviation may restrict the possible spacing of the cables. The optimum solution for a given project must be determined by detailed study.

On land, cables may be directly buried or installed in troughs. In some circumstances cables may be installed in a cable tunnel, but this is an expensive option and is reserved for applications such as installation in urban areas where other methods are impractical. As with submarine cables, detailed surveys and an appropriate choice of route are essential. Recommendations for laying and installation techniques are given in [57].

For directly buried installation, the cables are laid on a bed of sand in a trench which is back filled with cement bound sand to provide a controlled thermal resistance. Concrete covers are placed above the cables to provide protection against third party damage. The depth of burial is dependent on land use and is typically around 1 m.

For trough installation, a trench is excavated and a concrete trough is constructed. The cables are laid within the trough and the trough closed with reinforced concrete covers. As for directly buried cables, the trough may be back filled with cement bound sand to provide a controlled thermal resistance. Trough installation is used where limited space is available for the cable route.

Obstacles such as roads, railways and rivers may be crossed using techniques such as horizontal directional drilling (HDD). In HDD, a pilot hole is drilled which is then reamed to the required diameter and a conduit installed before the cables are pulled through. HDD may also be used in bringing submarine cables onshore.

The distance between cable joints is determined by the maximum size of cable drum that can be transported. The transport restrictions will be dependent on the particular project. The maximum length of cable is typically a few hundred metres. Joint bays will need to be provided at intervals along the cable route to accommodate the cable joints. For a.c. cables, link boxes will also be required for bonding and earthing of the cable sheaths.

Methods for calculating cable ratings are specified in BSI BS IEC 60287 [58, 59, 60, 61,62]. The standard is divided into three parts: Part 1 deals with current rating equations (100% load factor) and calculation of losses; Part 2 is concerned with calculation of thermal resistance and Part 3 is concerned with operating conditions. Calculation of cable ratings is generally simpler for HVDC cables than a.c. cables since skin and proximity effects do not need to be taken into account.

2.2.4. Offshore platforms

Although introducing a range of challenges not encountered in onshore locations, offshore platforms for a.c. substations and HVDC converter stations have been able to build on years of experience gained in the offshore oil and gas sectors.

Guidance on the design and construction of offshore a.c. substations for wind power plants is provided in CIGRE Ref. 483 [63]. The document addresses a range of considerations including risk management, maintenance, certification, definition of the single line diagram, specification of primary plant, physical layout and secondary equipment requirements.

An offshore platform for an a.c. substation consists of a topside, which houses the electrical equipment, and a supporting substructure. The substructure may be of monopole, jacket, gravity based or self-elevation type.

A monopole is a single steel pile, driven into the seabed. A jacket consists of four or more legs, with interconnecting bracing, attached to the seabed by piles. A gravity based foundation consists of a reinforced concrete or steel structure, filled with ballast and located directly on the sea bed. For each of these, the topside is transported to site by barge and installed on the substructure by a heavy lifting vessel.

The self-elevation platform is not dependent on heavy lifting vessels for its installation. It is designed as a floating structure, with four legs and a jacking system connected to the topside. It is towed to site and positioned, following which the legs are lowered by the jacking system. The choice of platform is dependent on many factors, including topside weight, water depth and seabed conditions.

Many of the considerations for offshore a.c. substations are applicable to offshore HVDC converter stations. At present, very few have been built and they are considerably larger than offshore a.c. substations. In comparison with offshore a.c. substations, they are a developing technology.

The first offshore HVDC converter stations, BorWin Alpha and DolWin Alpha, have been of jacket and topside construction [64, 65]. The jacket and topside construction is a flexible solution but dependent on heavy lifting vessels. Few lifting vessels with sufficient capacity to lift the topside of an offshore HVDC converter station exist and there is competition for their availability. The largest heavy lifting vessels, the Thialf and the Saipem 7000, have lifting capacities of 14 200 t and 14 000 t respectively [63]. A new heavy lifting vessel, the Pieter Schelte, with a topsides lifting capacity of 48,000 t is expected to be delivered in 2014 [66]. Shallow water and the width of the load have the effect of restricting the capacity. The lifting operation is dependent on a window of suitable weather.

Other platform designs are being pursued. The HelWin Alpha and BorWin Beta platforms are of a floating and self-installing type [67, 68]. A description of the BorWin Beta and HelWin Alpha platforms is given in [68]. The DolWin Beta platform is of a gravity base type with topside attached and will be self-installing [70].

2.3. Conclusions

An introduction has been provided to the technologies that might be used in an integrated offshore transmission network and issues relevant to their application have been highlighted. These issues will be of importance in the following chapters.

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3. Technology availability

3.1. Introduction

Many of the technologies required for integrated offshore transmission are new and developing rapidly. Voltage Sourced Converter (VSC) HVDC technology was introduced in 1997 and since then has been characterised by continuously increasing power transfer capabilities. Significant developments have taken place in the area of d.c. cables including the introduction of extruded and mass impregnated polypropylene paper laminate (MI PPL) insulation technologies. New devices are emerging, such as the HVDC circuit-breaker. The present chapter aims to anticipate how the capability of the key technology areas might develop in coming years and provide an indication of technology availability by year in order to inform planning decisions.

Figures are presented for each of the key technology areas, in which technology capability is tabulated against year. The availability of technology with a given capability in a given year is indicated by means of a colour-coded cell. The key is shown in Figure 1. Red indicates that the technology is not expected to be available in that year. It is important to distinguish between the time at which a technology becomes commercially available and the time by which it might be in service; amber indicates that the technology is expected to have been developed and to be commercially available but not yet in service. It has been assumed that project timescales for HVDC schemes are such that a period of typically four years would elapse between technology becoming available and being in service. It is clear that for technology to be in service, a contract will have to have been placed at the appropriate time. Consequently, a hatched green cell is used to indicate that it would be possible in principle for the technology to be in service in a given year provided a contract has been placed. A solid green cell indicates that the technology is in service or scheduled to be in service on the basis of contracts which are known to have been placed.

R	**Technology not available**
A	**Technology available but not in service**
G	**Technology potentially in service subject to contract**
G	**Technology in service or scheduled to be in service**

Figure 1: Key to figures

In this way, the time at which a technology is fully developed and ready to be offered to the market is identifiable by a change in cell colour from red to amber; the time at which a technology may first enter service is identifiable by a change in cell colour from amber to green or hatched green (depending on whether a specific contract has been placed).

Where the availability of a technology is indicated by an amber cell, its introduction will require an appropriate risk-managed approach that takes account of the lack of service experience. Where the availability is indicated by a green cell, a greater level of experience will be available but appropriate risk management will still be required particularly in the earlier years.

In deriving the forecast availabilities, published information has been used wherever possible. The sources of information are referenced in the text. Where no published information is available, forecasts have been based on a best estimate. The forecasts have not been confirmed or endorsed by the manufacturers. For technologies that are not yet available, the rate of development will depend on the level of demand and is therefore subject to change with market conditions.

3.2. Technology availability

3.2.1 HVDC technology

In the following sections, the component technologies that comprise an HVDC system are considered initially in isolation. Subsequently, the forecast capabilities of HVDC systems are determined by taking into account the forecast capabilities of the component technologies.

3.2.1.1 HVDC converters

The expected development in the capability of voltage sourced converter (VSC) HVDC technology is illustrated in Figure 2.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
1563 A	G	G	G	G	G	G	G	G	G	G	G	G	G
1800 A	A	A	A	A	G	G	G	G	G	G	G	G	G
2000 A	R	R	A	A	A	A	G	G	G	G	G	G	G

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 2: Voltage sourced converters

Where used with a d.c. cable circuit, the achievable power transfer capability for the converters will be dependent on the level of d.c. voltage permitted by the cable. The present generation of modular-multi-level converters are scalable by voltage and could reach the d.c. voltage level of any foreseeable cable with little development effort. The highest d.c. voltage for a VSC HVDC system presently on order is 500 kV pole-to-earth for the Skagerrak 4 project [1], which uses mass impregnated cables and is due to be operational in 2014. It is assumed that converters will continue to reach the level of d.c. voltage permitted by the cables as the technology develops.

The level of d.c. current achievable at present is determined by the IGBT modules used in the converter valves. A d.c. current of around 1600 A could be achieved with present technology. The interconnection between France and Spain [2], due to commission in 2014, comprises two HVDC links with a power transfer capacity of 1000 MW each and operating at ± 320 kV, representing a d.c. current of 1563 A.

VSC HVDC converters with d.c. current in excess of 1800 A are available [3], although no orders are known for this level of current at present. IGBT modules permitting d.c. currents of 2000 A are expected to be available for contracts placed in 2016 [4]. Achievement of higher d.c. currents may be possible in future years with further development of semiconductor devices and materials but would be dependent on the availability of cables able to carry such levels of current.

Line commutated converter (LCC) technology has developed to a stage where it could match the voltage and current ratings of any cable or overhead line with which it might be used on the GB transmission system. For example, the HVDC link connecting Jinping and Sunan in China operating at ± 800 kV d.c. and with a power transfer capability of 7200 MW went into service in 2013 [5]. No figure is given in the present document to illustrate the future development of LCC HVDC converter technology since it is unlikely to represent the limit on the capability of the system in which it is used within the GB transmission system.

3.2.1.2 HVDC cables

The expected availability of HVDC cables with extruded insulation is illustrated in Figure 3.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
320 kV	G	G	G	G	G	G	G	G	G	G	G	G	G
525 kV	A	A	A	A	G	G	G	G	G	G	G	G	G
600 kV	R	R	R	R	R	A	A	A	A	G	G	G	G
650 kV	R	R	R	R	R	R	R	R	R	R	A	A	A
700 kV	R	R	R	R	R	R	R	R	R	R	R	R	A

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 3: Extruded d.c. cables at 70 to 90 ºC

Extruded cables with a d.c. voltage of 200 kV are in service [6] and several projects using extruded cables with d.c. voltages of 300 kV and 320 kV are due to be commissioned in the next few years [7]. A 525 kV extruded d.c. cable system has been qualified [8].

With regard to cable development, CIGRE Ref. 533 published in April 2013 included the results of a questionnaire that had been sent to cable manufacturers [9]. One respondent indicated that extruded cables for a d.c. voltage of 600 kV would be available within the next five years and 750 kV within ten to fifteen years. Other manufacturers were also pursuing developments but tended to be less specific and more cautious with regard to their plans.

Figure 3 takes into consideration the range of forecasts for development of extruded cables together with a judgement of the likely timescales for development and testing.

The expected availability of HVDC cables with mass impregnated (MI) and mass impregnated paper polypropylene laminated (MI PPL) insulation is illustrated in Figure 4.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
500 kV	G	G	G	G	G	G	G	G	G	G	G	G	G
600 kV	A	A	G	G	G	G	G	G	G	G	G	G	G
650 kV	R	R	A	A	A	A	G	G	G	G	G	G	G
700 kV	R	R	R	R	R	R	A	A	A	A	G	G	G
750 kV	R	R	R	R	R	R	R	R	R	R	A	G	G

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 4: Mass impregnated d.c. cables at 55 ºC and mass impregnated polypropylene paper laminate cables at 80 ºC - voltage

MI cables are longer established than extruded cables and can achieve higher voltages at present. MI cables at 500 kV are in service on the SAPEI HVDC link between Sardinia and Italy [10]. The highest d.c. voltage for cables currently on order is 600 kV for the Western HVDC Link, scheduled to enter service in 2016 [11]. The questionnaire reported in the April 2013 CIGRE Ref. 533 also addressed the forecast development of MI cables [9]. In his response, one respondent indicated that MI cables for a d.c. voltage of 750 kV would be available within ten to fifteen years. Another expected to achieve a voltage level of 800 kV 'in the next few years'.

Figure 4 takes into consideration the range of forecasts for development of MI and MI PPL cables together with a judgement of likely timescales for development and testing.

MI cables may be used with LCC converters, which will be able to match the current carrying capability of the cable. The expected availability of MI cables according to current carrying capability is illustrated in Figure 5.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
1876A	A	A	G	G	G	G	G	G	G	G	G	G	G
2000 A	R	R	A	A	A	A	G	G	G	G	G	G	G

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 5: Mass impregnated cables at 55 ºC and mass impregnated polypropylene paper laminate cables at 80 ºC - current

The cables of the Western HVDC Link, scheduled to enter service in 2016, will achieve a current carrying capability in excess of 1800 A [10]. It has been assumed that, with some development, an increase in current carrying capability to 2000 A in the early years would be challenging but possible. This is consistent with the results of CIGRE Ref. 533 survey [9]. This does not represent a fundamental limit since the conductor cross section could be increased at the cost of more difficult cable installation.

3.2.1.3 Offshore platforms for HVDC converters

The forecast availability of offshore platforms for HVDC converters is illustrated in Figure 6.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
320 kV	G	G	G	G	G	G	G	G	G	G	G	G	G
400 kV	A	A	A	A	A	G	G	G	G	G	G	G	G
500 kV	A	A	A	A	A	A	G	G	G	G	G	G	G
600 kV	R	R	R	A	A	A	A	A	G	GG	G	G	G

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 6: Offshore platforms for HVDC converters

The achievable transmission capacity of offshore converters is dependent on the size and weight of the platforms which can be constructed and installed. The d.c. voltage, in particular, is subject to the limitations of platform physical dimensions due to the clearances in air required for insulation of the valves and d.c. equipment.

The highest d.c. voltage for offshore converters under construction at present is ± 320 kV, for which a number of examples exist [12, 13, 14]. Based on installation vessel lifting capability and fabrication yard size, a ± 400 kV offshore converter is thought to be deliverable. A new or upgraded installation vessel would allow an increase in d.c. voltage to around ± 500 kV. The lifting vessel Allseas Pieter Schelte, expected to be delivered in the second half of 2014, will increase the largest available lifting capacity significantly (topsides lift capacity 48,000 t) [15]. However, an increase in fabrication yard size would be required to exploit the full capacity of the vessel. Higher d.c. voltages could also be achieved, in principle, by adopting a modular converter design for installation in two or more lifts. Further design work would need to be carried out to establish the feasibility of such a solution.

3.2.2 HVDC systems

The forecast capability of systems comprising HVDC converters and d.c. cables is determined from the forecast capability of the component technologies illustrated in the previous figures. The achievable MVA rating in a given year is determined from the d.c. current and d.c. voltage permitted by the component technologies.

The availability of a given MVA rating in a given year is determined by whichever of the component technologies has the lowest availability. Many combinations of component d.c. current and d.c. voltage are possible; results are shown in the figures where an increase in d.c. current, d.c. voltage or both allows a higher MVA rating for the system to be achieved. If a given MVA rating is available in a given year, it follows that any lower value of MVA rating will also be available. The combination of d.c. current and d.c. voltage permitting the increase in MVA rating is indicated in the figures.

The maximum real power transmissible by the system may be less than the MVA rating, depending on requirements for converters to provide reactive power. For line commutated converters, reactive compensation plant is always provided as part of the scheme.

3.2.2.1 HVDC systems with converters located onshore

The availability of HVDC systems where VSC converters located onshore are used with extruded cables is illustrated in Figure 7.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	
1000 MVA	G	G	G	G	G	G	G	G	G	G	G	G	G	320 kV 1563 A
1890 MVA	A	A	A	A	G	G	G	G	G	G	G	G	G	525 kV 1800 A
2100 MVA	R	R	A	A	A	A	G	G	G	G	G	G	G	525 kV 2000 A
2400 MVA	R	R	R	R	R	A	A	A	A	G	G	G	G	600 kV 2000 A
2600 MVA	R	R	R	R	R	R	R	R	R	R	A	A	A	650 kV 2000 A
2800 MVA	R	R	R	R	R	R	R	R	R	R	R	R	A	700 kV 2000 A

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 7: HVDC systems comprising voltage sourced converters and extruded cables

The France-Spain Interconnector, which combines VSC converters and extruded cables, will achieve a power transfer capability of 1000 MW following commissioning in 2014 [2]. The forecast increases in d.c. current and voltage levels of the converters and cables allow a continuing increase in the achievable MVA rating. The figure indicates that a 2000 MVA solution would be commercially available by 2017 and might potentially be in service by 2021.

The availability of HVDC systems where VSC converters located onshore are used with mass impregnated cables is illustrated in Figure 8.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	
1400 MVA	G	G	G	G	G	G	G	G	G	G	G	G	G	500 kV 1400 A
2160 MVA	A	A	A	A	G	G	G	G	G	G	G	G	G	600 kV 1800 A
2600 MVA	R	R	A	A	A	A	G	G	G	G	G	G	G	650 kV 2000 A
2800 MVA	R	R	R	R	R	R	A	A	A	A	G	G	G	700 kV 2000 A
3000 MVA	R	R	R	R	R	R	R	R	R	R	A	A	A	750 kV 2000 A

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 8: HVDC systems comprising voltage sourced converters and mass impregnated cables

The greater d.c. voltage permitted by mass impregnated cables compared with extruded cables allows greater MVA ratings to be achieved in a given year. The Skagerrak 4 project [1] combines VSC converters with MI cables to achieve a power transfer capability of 700 MW with a single pole operating at 500 kV d.c. Consequently, although Skagerrak 4 is a monopole, the technology would allow 1400 MVA to be achieved with two poles operating at ± 500 kV. Skagerrak 4 is due to be commissioned in 2014. However, the d.c. current of around 1400 A is within present limits and, in principle, 1563 MVA or more could be achieved with existing technology. The expected developments in converter current and cable voltage indicate that a 2000 MVA solution might potentially be in service by 2019.

The availability of systems where line commutated converters located onshore are used with mass impregnated cables is illustrated in Figure 9.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	
2250 MVA	A	A	G	G	G	G	G	G	G	G	G	G	G	600 kV, 1875 A
2600 MVA	R	R	A	A	A	A	G	G	G	G	G	G	G	650 kV, 2000 A
2800 MVA	R	R	R	R	R	R	A	A	A	A	G	G	G	700 kV, 2000 A
3000 MVA	R	R	R	R	R	R	R	R	R	R	A	A	A	750 kV, 2000 A

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 9: HVDC systems comprising line commutated converters and mass impregnated cables

In contrast to systems using voltage sourced converters, the d.c. current will not be limited by the capability of the converter but by that of the cables. A solution with a power transfer capability of 2250 MW will be in service in 2016 on commissioning of the Western HVDC Link [11]. Further increases will be possible, largely enabled by increases in cable d.c. voltage. Beyond 2016, however, the d.c. current capability of the voltage sourced converter is expected to have converged with that of the cables. From this point on, the power transfer capability of HVDC systems using line commutated converters will no longer be greater than that achievable with voltage sourced converters.

3.2.2.2 HVDC systems with converters located offshore

Where HVDC converters are located offshore, the size of the available platform may impose a limit on the d.c. voltage of the system. The achievable MVA rating in a given year is therefore determined by the lower of the d.c. voltages permitted by the cable and platform.

The availability of HVDC systems comprising VSC converters and extruded cables where one converter or more is located offshore is shown in Figure 10.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	
800 MVA	G	G	G	G	G	G	G	G	G	G	G	G	G	320 kV 1250 A
1440 MVA	A	A	A	A	A	G	G	G	G	G	G	G	G	400 kV 1800 A
1800 MVA	R	A	A	A	A	A	G	G	G	G	G	G	G	500 kV 1800 A
2000 MVA	R	R	A	A	A	A	G	G	G	G	G	G	G	500 kV 2000 A
2400 MVA	R	R	R	R	R	A	A	A	A	G	G	G	G	600 kV 2000 A

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 10: HVDC systems comprising voltage sourced converters and extruded cables (offshore)

The DolWin Alpha offshore converter station, installed in 2013, has achieved a d.c. voltage of ±320 kV [7]. However, the d.c. current of the link, at around 1250 A, is well within present limits. In principle, an offshore converter with a rating of 1000 MVA or more could be achieved with existing technology, but allowance needs to be made for the project delivery time.

Comparison of Figure 10 with Figure 7 shows that offshore platform size does not impose a significant restriction on the capability of HVDC systems with extruded cables over the range of voltage considered (up to 600 kV d.c.).

The availability of HVDC systems comprising VSC converters and mass impregnated cables where one converter or more is located offshore is shown in Figure 11.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	
1440 MVA	A	A	A	A	A	G	G	G	G	G	G	G	G	400 kV 1800 A
1800 MVA	A	A	A	A	A	A	G	G	G	G	G	G	G	500 kV 1800 A
2000 MVA	R	R	A	A	A	A	G	G	G	G	G	G	G	500 kV 2000 A
2400 MVA	R	R	R	A	A	A	A	A	G	G	G	G	G	600 kV 2000 A

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 11: HVDC systems comprising voltage sourced converters and mass impregnated cables (offshore)

Comparison of Figure 11 with Figure 8 shows that the offshore platform imposes a restriction on d..c voltage such that the capability of MI cables cannot be exploited fully. The use of mass impregnated cables in such applications offers little or no increase in rating beyond that which can be achieved with extruded cables.

3.2.3 HVDC protection and control

The availability of control and protection for VSC HVDC systems is illustrated in Figure 12. The figure shows the expected availability of protection and control VSC HVDC systems of increasing complexity, i.e. two-terminal systems, multi-terminal systems and multi-terminal systems with multi-vendor interoperability.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Control (two-terminal)	G	G	G	G	G	G	G	G	G	G	G	G	G
Protection (two-terminal)	G	G	G	G	G	G	G	G	G	G	G	G	G
Control (multi-terminal)	G	G	G	G	G	G	G	G	G	G	G	G	G
Protection (multi-terminal)	G	G	G	G	G	G	G	G	G	G	G	G	G
Control (multi-terminal, multi-vendor)	A	A	A	A	G	G	G	G	G	G	G	G	G
Protection (multi-terminal, multi-vendor)	A	A	A	A	G	G	G	G	G	G	G	G	G

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 12: HVDC protection and control

For two-terminal ('point-to-point') VSC HVDC schemes, including connections to wind generation, both protection and control are well established and the technology has been in service since 1997 [16, 17].

Protection and control for multi-terminal VSC HVDC schemes are less well established. The world's first multi-terminal VSC HVDC systems have recently been commissioned.

The first three-terminal VSC HVDC system was commissioned at Nan'ao in China in December 2013 [18]. SEPRI (Electric Power Research Institute, China Southern Power Grid), had technical responsibility for the project, in which three different control and protection suppliers were involved.

The first five-terminal VSC HVDC system was commissioned in Zhoushan in China in June 2014 [19]. The control and protection systems were provided by a single supplier.

A further development in protection and control technology for VSC HVDC systems is the achievement of multi-vendor interoperability, such that a VSC HVDC system may be extended in the future by the connection of further terminals without being restricted to the original supplier.

A contract was awarded for a VSC HVDC connection forming the first phase of the South West Link, in Sweden, in January 2012 [20]. The scheme has been designed to permit future extension by the connection of additional terminals to form a multi-terminal link [21].

A greater level of complexity is represented by the Atlantic Wind Connection in the US. The project is planned to be built in stages to form an offshore multi-terminal VSC HVDC network spanning the east coast from New Jersey to Virginia. When complete, it will facilitate the connection of more than 7000 MW of offshore wind generation while reinforcing the onshore transmission system [18]. Suppliers have been announced for the first phase of the New Jersey Energy Link, which will form the initial segment of the project. The first phase comprises a multi-terminal VSC HVDC link with two onshore converter stations and one offshore converter station and is due to be in service in 2019 [23].

At present, no standards exist for the control and protection of multi-terminal VSC HVDC systems. Working Bodies within both CIGRE and CENELEC are addressing the issues of control and protection for multi-terminal HVDC systems and it seems likely that standard solutions will be developed within the next few years.

With regard to protection and control technology, therefore, it is concluded that for two-terminal VSC HVDC systems, service experience exists. For multi-terminal applications, the technology is commercially available and recently put into service. It would be possible for a solution with multi-vendor interoperability to be in service by 2018, but no contracts are known to have been placed at present.

It should be emphasised that the interaction of any HVDC link with the a.c. system or systems to which it is connected may raise issues related to its protection and control that are not covered by any of the above and further guidance is needed. The requirements for each scheme will need to be assessed and the risks evaluated.

3.2.4 HVDC circuit-breakers

The expected availability of the HVDC circuit-breaker is illustrated in Figure 13.

2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	
A	A	A	A	G	G	G	G	G	G	G	G	G	320 kV, 2000 A
R	R	A	A	A	A	G	G	G	G	G	G	G	550 kV, 2000 A

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 13: HVDC circuit-breaker

A hybrid HVDC circuit-breaker has been demonstrated in the laboratory [24]. The device is designed for a rated voltage of 320 kV, a rated current of 2 kA and a current breaking capability of 9 kA. Allowing for project timescales, it might potentially be in service by 2019. The manufacturer envisages that the next generation of semiconductor devices will allow an increase in the breaking current to 16 kA [24]. The increase in rated voltage that this would facilitate is dependent on the current limiting reactor that is used with the HVDC breaker which may itself be subject to limitation in size. For the purposes of Figure 13, it has been estimated that a rated voltage in excess of 550 kV would be achievable and that such a device might potentially be in service by 2021.

The above is consistent with the results of a questionnaire sent to prospective HVDC breaker manufacturers and published in CIGRE Ref. 533 in April 2013 [8], where one respondent indicated that HVDC breakers operating at > 500 kV with a breaking capacity of 16 kA would be available within five years. Another indicated that a > 500 kV device would be available within 10 years.

3.2.5 HVDC gas-insulated switchgear (GIS)

Gas-insulated switchgear (GIS) is a compact alternative to conventional air-insulated switchgear. It has been widely used in a.c. systems for a number of years in applications where space is limited, such as substations located in urban areas. At present, however, GIS has not been widely applied to HVDC systems. Under the influence of a d.c. electric field, charge tends to accumulate on solid insulation [25]. The accumulated charge distorts the electric field and may reduce the performance of the insulation system. The need for compact HVDC switchgear for offshore application might drive the development of HVDC GIS. At present, however, no HVDC GIS is known to be commercially available.

3.2.6 Offshore platforms for a.c. substations

Offshore a.c. substations are of significantly smaller size and weight than those required for HVDC converter stations and the required power transfer capacity can usually be achieved without great difficulty.

3.2.7 AC cables

With the proliferation of offshore wind farms globally, a.c. submarine technology has seen rapid development lately. Both single (1c) and three core (3c) solutions have been in service for decades using fluid filled (1c) and paper and oil individual lead sheaths (3c) at a wide range of power and voltage applications. Extruded cross linked polyethylene (XLPE) cable types have formed the bulk of the a.c. submarine cable market for the last five years [26].

3.2.7.1 Three core a.c. submarine cables

Three core cable designs offer a good solution to the problems of losses in the armour as the three differently phased magnetic fields in trefoil formation largely leads to the cancellation of magnetic fields which reduces circulating currents in the armour allowing the use of more conventional (lower cost) steel wire armouring (SWA).

The trefoil formation does have some thermal disadvantages, but this is helped to some extent by the generally lower ambient temperatures in water (compared to land).

The consolidation of three cores into a single cable means that just a single installation run is required, although the material costs are generally greater than the costs of three individual cables, so for shorter distances, single core solutions may prove more cost effective.

Single cables with three cores of up to 230 mm diameter and weights of nearly 100 kg / m have been built at voltages up to 245 kV [27], with a 420 kV cable rated at 500 MW on order [28].

Conductor sizes of more than 1000 mm^2 are believed to be possible [29]. A cable length of just over 100 km has been achieved at a voltage of 132 kV [30]. Unfortunately the physics (increasing capacitive effects) disadvantages higher voltage cables with the economic range of 400 kV and higher voltage cables reducing to not much more than 20 km. 220kV is a useful voltage allowing a good compromise between power delivery and transmission distance, but there is no voltage standardisation within the offshore industry yet and 245 kV and 275 kV solutions are also possible.

The technology is likely to be limited by the capability of factory extrusion lines to manufacture the larger sized common over sheaths and armouring required for increasing conductor sizes. Handling difficulties both on and offshore will also play a role as weights beyond 100 kg / m could prove challenging. Lighter “filler” materials with better thermal properties could bring benefits as the technology matures.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
500 MW	G	G	G	G	G	G	G	G	G	G	G	G	G
600 MW	A	A	A	A	G	G	G	G	G	G	G	G	G
700 MW	R	R	R	R	A	A	A	A	G	G	G	G	G

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 14: Three core a.c. submarine cables

3.2.7.2 Single core a.c. submarine cables

Single core solutions benefit from the improved thermal characteristics associated with flat configurations and increased spacing between cores (as well as the differential between sea and land temperatures), but suffer from the consequences of unbalanced magnetic fields normally resolved by the use of cross bonding on land. This requires the use of conductive armours (to reduce circulating currents and armour losses). As these can often be of almost the same cross section as the conductors, material costs can be high compared to the equivalent land cables and three installation runs are likely to be required.

The single core designs are however free to use much larger conductor sizes than 3c cables (theoretically up to 3000 mm^2) and so very large power transfers are possible [31].

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
1000 MW	G	G	G	G	G	G	G	G	G	G	G	G	G
1200 MW	A	A	A	A	G	G	G	G	G	G	G	G	G
1300 MW	A	A	A	A	A	A	A	A	G	G	G	G	G

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 15: Single core a.c. submarine cables

3.3. Conclusions

The likely availability of key technologies for integrated offshore transmission has been forecast, based on current state-of-the art and, wherever possible, on known developments. Overall, increasing trends are seen in power transfer capability and in the functionality of VSC HVDC links that are likely to play an increasingly important role as the GB transmission system accommodates increasing volumes of renewable generation in the coming years. Key developments that are expected include:

- an increase in d.c. current of VSC HVDC converters as higher power semiconductor devices become available
- a continuing increase in the d.c. voltage of both extruded and mass impregnated d.c. cables
- developments in the technology of offshore platforms for HVDC converters allowing higher power transfer capabilities

- the application of multi-terminal VSC HVDC systems
- the achievement of interoperability between HVDC equipment of different suppliers
- the introduction of the HVDC circuit-breaker

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4. Unit Costs

4.1 Introduction

The main goal of the IOTP (E) project is to determine the scope and viability of integrated solutions between the various Round Three Wind Farm regions.

The Technology workstream was tasked with obtaining and agreeing a set of unit costs for each technology. A range of costs was to be provided to allow complexity factors to be taken into account.

These costs were then to be used by the Systems Requirements Workstream to complete the Cost Benefit Analysis across multiple options.

4.2 Methodology

A Strategy for obtaining unit costs was developed and agreed within the workstream. See Appendix N (Technology Workstream Strategy for obtaining unit costs Rev 1)

In practice the programming of the IOTP(E) project provided the opportunity to utilise the costs developed for National Grid's Electricity Ten Year statement (ETYS) 2013 [2] and so these have formed the basis of the IOTP(E) unit costs.

4.2.1 Methodology for obtaining costs for ETYS 2013

It has proved almost impossible to get indicative costs directly from the marketplace and very difficult to get engagement with suppliers without a definite project with clear commissioning dates.

In practice, the round of canvassing suppliers to inform the unit costs in 2013 brought little additional unit cost information. Questionnaires were sent out to the same set of suppliers as for the ODIS cost exercise in 2011.

Unfortunately, very few suppliers responded in 2013. Where comments from submissions could be kept anonymous these have been incorporated, but for the most part the ETYS 2013 results are the same as the 2011 results, but inflated to 2013 values.

The exceptions to this are a.c. and d.c. Platforms where the original emphasis on water depths have been replaced with topside weights and new Tables have been derived. The derivation of the new platform tables will be described later.

4.2.2 Choice of Indices

Consideration was given to a number of inflation indicators. Because most of the project cost information available in the media was being quoted in Euros, it was felt that a consolidated Harmonised Index of Consumer Prices (HICP) value for the European Union would be the most appropriate.

The 2011 ODIS values were therefore inflated by:-

2011/12	3.1 %
2012/13	2.6 %

In comparison, the equivalent UK values were:-

2011/12	4.5 %
2012/13	2.8 %

(UK inflation over the 2 year period was 1.6 % higher overall).

4.2.3 Commodity Prices

The commodity prices of interest to the electricity industry have steadied since December 2010 and Copper, Aluminium and Lead prices have all been decreasing at roughly similar rates.

The exception to this trend being the Steel price which dropped sharply during 2012 while the other three metals levelled. This could be because it is a 3 month futures price, rather than a spot price. The Steel price rallied in 2013.

Figure N Graphs showing commodity price changes in the last four years for Copper, Aluminium, Lead and Steel.

Note that all metal prices have been quoted in GBP whilst most offshore transmission projects will be bought in Euros and the Pound / Euro exchange rate which has favoured the Euro in this period has had a large influence on the unit costs of UK offshore transmission equipment.

The impact of metal prices and exchange rates on unit costs will depend very much on the constituent components and the proportions affected by these factors. [10] Unfortunately whereas the exchange rate costs of wind turbines might be displaced with domestic manufacturing, it is unlikely that there will be any domestic manufacturing of converters, platforms or submarine cables.

In order to make optimum use of commodity pricing it is necessary to have a good feel for the relative quantities of these and other materials in each of the units. This is straightforward for the more familiar equipment types of onshore equipment, where there are six decades of cost history, but this information is not readily available for all technologies and is particularly scarce for the newer technologies, especially VSC converters and HVDC converter platforms.

Most options being compared in the various scenarios use similar equipment using similar baskets of materials, but at differing scales.

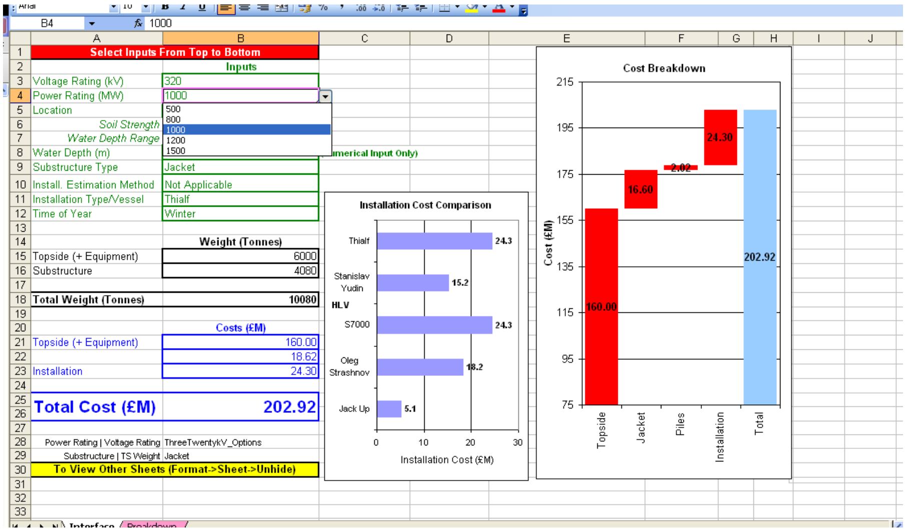
In the light of this it was felt that further work is required to get value from the use of commodity prices for unit costing and it is a recommendation that research work in this area be initiated now to inform the unit costs used in the next phase of this project.

4.2.4 Derivation of Platform costs.

In 2011 National Grid initiated a study from an established consultancy in the Petro-chemical industry to derive a costing tool for offshore platforms. This included insight into the installation and auxiliary plant requirements of offshore platforms and the necessary ancillary facilities for supporting High Voltage electrical transmission in the North Sea.

NG have used this work to derive weights and dimensions for our cost models for a.c. and d.c. Platforms.

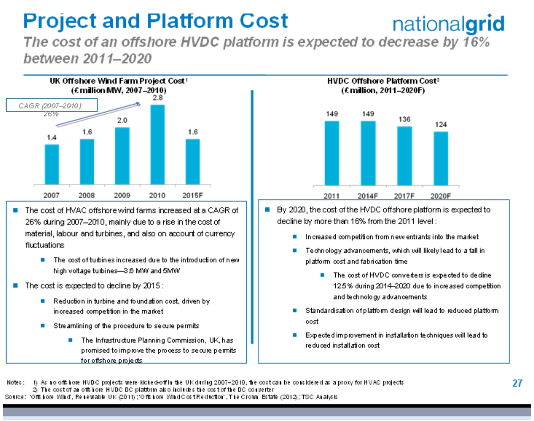
This resulted in a change of focus in the platform unit cost tables from a water depth centric method to one in which the lift related requirements of platforms (amongst others) were considered.

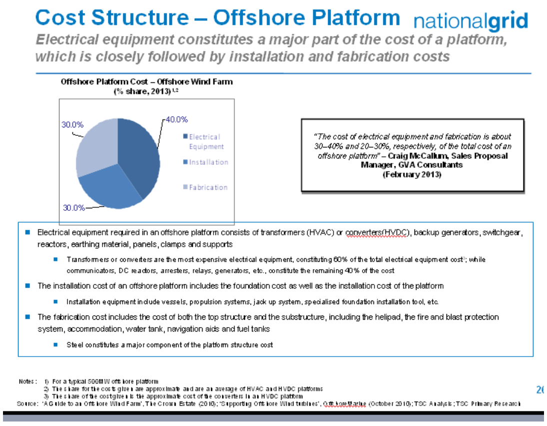


This work was augmented by a desktop market research study done in January 2013 on a.c. and d.c. platforms. This gave assumed growth figures from the platform industry including both suppliers and fabricators. Also included were cost breakdowns for eight previous/ current projects.

The headline findings were that a cumulative annual growth rate of 16.5% was expected for the HVDC platform industry. This growth rate would provide a level of certainty of development in the sector allowing the suppliers to invest in more capability and capacity, allowing for more competition in offshore projects. This would bring about standardisation with increasing offshore project experience and potentially reduce the unit cost for assets.

The growth rate is consistent with other studies that have been done looking at HVDC transmission from 2013-2018 by Marketsandmarkets. Supplier analysis showed trends towards partnerships at work in a number of projects.





A set of estimated total platform costs were produced. Electrical equipment costs are said to contribute to 35% of the total HVDC platform installed cost.

(For HVDC it is EE x (1/0.35)) = 2.8).

(For HVAC it is EE x (1/2.6 = 3.8)).

We checked our figures against costs provided by manufacturers and also against project costs in the public domain and found that they were within tolerances of +/- 10% of our estimates.

New figures suggested increases of 40 % on 2011 figures were in order. Even taking this large increase into account these costs still fell within the calculated cost range.

4.2.5 Use of ETYS 2013 costs for IOTP(E)

Once the ETYS costs were derived they went through a further set of internal governance and were then passed to the IOTP(E) Technology Workstream and to the System Requirements Workstream for comments.

As a result of these comments a number of units which would inform the CBA were introduced. These include 320 kV 1000 MW and 500 kV 1800 MW VSC Converters; 220/ 33 kV Transformers; 120 and 200 MVAr 220 kV Reactors and also a 150 MVAr Static Var Compensator. Changes were made to the voltage and power ranges of some units where power ratings outside the area of interest were removed.

VSC converter upper range cost scaling was derived using a method described in CIGRE brochure 388 (For LCC), less 10% and with dollars converted to pounds.

4.3 Comparisons with other sources.

4.3.1 Comments from workstream

Contributions to the unit cost exercise from the workstream members have generally been commensurate with project experience. Unfortunately nobody in the workstream has any tendered costs for HVDC projects, although everybody has contributed some budget numbers received from manufacturers.

Note that the Basslink, Britned and Nemo projects are part of National Grid Business Development and the regulated National Grid businesses do not have access to cost or technical information from these projects. Also these projects are designed to a very different business model to the likes of Western Link which is designed for Transmission between two parts of the same network, and operation over a 40 year life. This is different again to the Integrated Offshore models, where most assets are designed to a life matching the leases on the Windfarm sites.

National Grid's technical experience with submarine a.c. cables was pioneering with the Isle of Mann cable, but there is little recent submarine a.c. experience to derive costs from.

There was an initial reticence to contribute in open sessions, and a strong awareness that the developers are in competition with each other. But useful comments on costs have now been given individually although these have had to be anonymised.

A review of the Round 3 project ratings and distances from shore mean that many of the Round one and two units may not be relevant for Round three solutions. For example most developers were considering 220 kV and not 132 kV three phase cables between collector stations. 220 kV is also preferred for most IOTP(E) integration options to provide the higher ratings required and to reduce the number of cables.

The most contentious area is that of HVDC platform costs where some developers feel that the costs are too low by about £100 – 150 m. An exercise to clarify public domain information for one of the current German offshore projects (which is a key reference) by asking those directly involved has unfortunately not been successful.

It is therefore recommended that further research work be commissioned to explore the composition and costs associated with HVDC Platforms – an exercise to determine the makeup and costs of a 2GW VSC platform would be extremely valuable.

The other area of contention are the costs of the a.c. switchgear and other platform based equipment necessary for the actual integration between converter platforms. Whilst these are generally thought to have second order effects as they can be incorporated directly into platform designs at an early stage at which time they should not greatly contribute to the overall project costs.

The a.c. switchgear costs in ETYS are higher than recent NG quotes for comparable unlicensed work and therefore probably contain some allowance for additional infrastructure.

There is however, some small risk, and larger concerns that these relatively compact components might push the platform design into needing significant additional infrastructure at considerable extra cost, especially if retrofitted.

4.3.2 Costs associated with Energy Absorption

Whilst the review of the a.c. islanding question is still ongoing and it is not clear how much of a problem this is, it is possible that some energy absorbing equipment will be required.

There is a view that this functionality may best be introduced in a distributed way at medium voltage and that in this way the need for significant additional deep sea platform space will be assuaged. Certainly it is likely to be more cost effectively located on a.c. platforms or within the turbine structures than on d.c. platforms. The £50 m proposed as a budget figure to cover against this risk, being nearly half the cost of a converter station, might then be significantly reduced.

Unfortunately while we are very interested in exploring this technology in more detail, our brief for this project is to identify areas requiring further development and where possible to set the research work in motion, but not necessarily to completely close out the issues.

We would need closer understanding of the potential specifications of the devices before we could usefully engage with the suppliers for costs.

It is recommended that further work is done to establish the system needs, equipment specifications and unit costs at the earliest opportunity.

4.3.3 Comparisons to TNEI/PPA Energy, 'Offshore Transmission Coordination Project – Final Report for the Asset Delivery Workstream', December 2011

This report has broadly based costs on NG ODIS 2010 figures with a comment that actual platform costs are thought to be 25 – 30 % lower than those quoted (this prior to recent German Experience) and actual cable costs were thought to be 10 – 15% less than those quoted.

4.3.4 Comparison to ENTSO-E Costs.

The unit cost information contained in the ENTSO-E Report (European Network of Transmission System Operators for Electricity) 'Offshore transmission technology', November 2011 was derived from the ODIS 2011 Report. This is confirmed on the very bottom of page 35 of the ENTSO-E report (as reference 7).

4.3.5 Comparisons to OffshoreGrid, 'Offshore electricity infrastructure in Europe – A techno-economic assessment', Final Report, October 2011

The document has a table showing the cost differences between nations but no unit cost information.

4.4 Unit Cost Tables

4.4.1 Voltage Source Converters

Specifications	**Cost (£M)**
500MW 300kV	68 - 84
850MW 320kV	89 - 110
1000MW 320 kV	98 - 124
1200MW 400kV	108 - 136
1800MW 500kV	116 - 168
2000MW 500kV	131 - 178

Includes Civils / Building

4.4.2 Current Source Converters

Specifications	Cost (£M)
1000MW 400kV	73 - 94
2000MW 500kV	136 - 168
3000MW 600kV	178 - 209

Includes Civils / Building

4.4.3 Transformers

Specifications	Cost (£M)
180MVA 132/33/33 or 132/11/11kV	1.05 - 1.9
240MVA 132/33/33kV	1.26 - 2.09
250 MVA 220/33/33kV	1.85 - 2.15
120MVA 275/33kV	1.26 - 1.68
240MVA 275/132kV	1.57 - 2.09
240MVA 400/132kV	1.88 - 2.30

Excludes civil works

4.4.4 HVAC Swichgear

Specifications	Cost (£M)
132kV	1.15 - 1.47
220kV	2.85 - 3.15
275kV	3.04 - 3.46
400kV	3.98 - 4.29

Includes protection and Infrastructure

4.4.5 Shunt Reactors – supplied cost

Specifications	Cost (£M)
60MVAr/13kV	0.52 - 0.84
120MVAr/220 kV	2.25 - 2.75
200MVAr/220 kV	2.75 - 3.25
100MVAr/275kV	2.30 - 2.51
200MVAr/400kV	2.51 - 2.72

Excludes civil works

4.4.6 HVAC Shunt capacitors – Installed cost

MVAr of capacitive reactive compensation	Cost (£M)
100	3.14 - 5.24
200	4.19 - 7.33

Includes civil works – (land)

4.4.7 Static VAR compensators- Installed cost

MVAr of reactive compensation	Cost (£M)
100	3.14 - 5.24
150	9 - 13.5
200	10.47 -15.71

Includes civil works – (land)

4.4.8 STATCOMs – Installed Cost

MVAr of reactive compensation	Cost (£M)
50	3.14 - 5.24
100	10.47 - 15.71
200	15.71 - 20.94

Includes civil works – (land)

4.4.9 Extruded HVDC Cables – Supply only

GBP per metre	Cost (£/m)	Rating (MW)
Cross Sectional Area	**320 kV**	**320 kV**
1200mm2	314 - 471	560
1500mm2	346 - 471	636.8
1800mm2	314 - 524	704
2000mm2	366 - 576	752

Use Sub-sea cable installation costs per kilometre in 4.3.5.13 below

4.4.10 HVDC Mass impregnated (excluding PPLL)

a) 400 kV

GBP per metre	Cost (£/m)	Rating (MW)
Cross Sectional Area	**400 kV**	**400 kV**
1500mm2	366 - 576	892
1800mm2	418 - 576	1200
2000mm2	418 - 628	1400
2500mm2	627 - 733	1500

b) 500 kV

GBP per metre	**Cost (£/m)**	Rating (MW)
Cross Sectional Area	**500 kV**	**500 kV**
1500mm2	418 - 576	1115
1800mm2	428 - 628	1500
2000mm2	418 - 681	1750
2500mm2	524 - 785	1880

Use Sub-sea cable installation costs per kilometre in 4.3.5.13 below

4.4.11 HVAC 3Core Cables

MVA Rating	**Voltage**	**Cost (£/m)**
180	132kV	471 - 733
300	220kV	524 - 785
400	245kV	681 - 1047

Use Sub-sea cable installation costs per kilometre in 4.3.5.13 below

4.4.12 HVAC 3 phase OHL

Description	**Cost (£M)**
Cost per route km 400kV, double circuit	1.57 - 1.99
Cost per route km 132kV, double circuit	0.73 - 0.94
Cost per route km 132kV, single circuit	0.52 - 0.63

Installed

4.4.13 Subsea Cable Installation

Installation Type	**Cost (£M/km)**
Single cable, single trench	0.31 - 0.73
Twin cable, single trench	0.52 - 0.94
2 single cables; 2 trenches, at least 10M apart	0.63 - 1.26

These are generalised as seabed conditions will strongly influence costs, as will length (mobilisation); crossings and environmental factors.

4.4.14 DC Platforms

Ratings	**Weight**	**Cost (£M)**
1000 MW @ 320-400 kV	8000-10250	260 - 329
1250 MW @ 320-400 kV	9500-14000	281 - 385
1500 MW @ 450-500 kV *	17000-27500	352 - 496
1750 MW @ 450 550 kV *	20000-30000	414 - 530
2000 MW @ 500-600 kV *	24500-33000	419 - 534
2250 MW @ 600-700 kV *	29500-39250	480 - 588
2500 MW @ 650-750 kV *	32000-43000	506 - 638

4.4.15 AC Platforms

Ratings	Cost (£M)
200-400 MW 33 kV arrays @ 132-150 kV *	30 - 55
200- 400 MW 33 kV arrays @ 220 -275 kV	36-44
400-700 MW 66 kV arrays @ 220 - 275 kV	45 - 81
700 -1000 MW 66 kV arrays @ 220 - 275 kV	70 - 134

4.5 Extract from Technology Working Group Terms of Reference Issue 4, 31 May 2013

2. Unit costs

Unit costs will be identified for each technology area for optioneering purposes. A range of costs will be obtained to reflecting the complexity factors associated with different locations.

4.6 Strategy for Obtaining Costs

INTEGRATED OFFSHORE TRANSMISSION PROJECT (EAST)

TECHNOLOGY WORKSTREAM STRATEGY FOR OBTAINING UNIT COSTS

4.7 PURPOSE AND SCOPE

One of the four main deliverables of the Technology Workstream is to obtain unit costs for the components of an integrated offshore transmission network for use in cost benefit analysis. The report on unit costs is required by 27 September 2013. The present paper sets out the strategy by which it is intended to obtain the unit costs.

4.7.1 BACKGROUND

Unit costs are required for the components of an integrated offshore transmission network as follows:

HVDC converters, including transformers and switchgear, located onshore

HVDC converters, including transformers and switchgear, located offshore

AC collector substations, located offshore

DC cables, land and submarine

AC cables, land and submarine

DC circuit-breakers

The unit costs are required to reflect a range of system transmission capacities from 1000 to 2 500 MW.

Few contracts have been placed for projects using technology applicable to offshore transmission and cost information is scarce. Costs will differ between projects due to project complexity, changes in commodity prices, variation in exchange rates, the required ratings, market elasticity and other factors.

4.7.2 STRATEGY

Unit costs for the applicable technologies have been published in National Grid's Offshore Development Information Statement (ODIS) [1]. The unit costs were based on information received from equipment suppliers in response to a questionnaire. ODIS was last published in 2011 and has since been superseded by the Electricity Ten Year Statement (ETYS). The 2012 ETYS [2] did not include unit costs, but unit costs are being sought for the 2013 publication. Timescales, however, will probably preclude the use of 2013 ETYS information for IOTP(E).

It is proposed to use costs from ODIS 2011 costs increased to account for inflation and changes in commodity costs. Comparison will be made with information from other sources where costs have been published [3, 4, 5] to ensure consistency. Additionally, comparison will be made with contract prices published in press releases for appropriate projects.

CIGRE JWG B2/B4/C1.17 [6] published an empirical formula which may be used to scale converter costs as a function of power and d.c. voltage. It will therefore be possible to obtain indicative costs for converters for which no published costs exist. Guidance will also be taken from CIGRE B4.46 [7] and B4.52 [8].

The indicative costs obtained for offshore platforms will be circulated to the developers with a request to advise suitable complexity factors to account for sea bed conditions, water depth, and so forth so that a range of costs reflecting different project conditions may be obtained.

4.8 REFERENCES

1. 2011 Offshore Development Information Statement, September 2011, www.nationalgrid.com

2. 2012 Electricity Ten Year Statement, November 2012, www.nationalgrid.com

3. TNEI/PPA Energy, 'Offshore Transmission Coordination Project – Final Report for the Asset Delivery Workstream', December 2011

4. ENTSO-E (European Network of Transmission System Operators for Electricity) 'Offshore transmission technology', November 2011

5. OffshoreGrid, 'Offshore electricity infrastructure in Europe – A techno-economic assessment', Final Report, October 2011

6. CIGRE JWG B2/B4/C1.17, 'Impacts of HVDC lines on the economics of HVDC projects', CIGRE Ref. 388, August 2009

7. CIGRE B4.46, 'Voltage source converter (VSC) HVDC for power transmission – Economic aspects and comparison with other a.c. and d.c. technologies', CIGRE Ref. 492, April 2012

8. CIGRE B4.52, 'HVDC grid feasibility study', CIGRE Ref. 533, April 2013

4.8.1 Unit Cost Report References

1. 2013 Electricity Ten Year Statement Technology Appendix p 52

2. 2011 Offshore Development Information Statement, September 2011, www.nationalgrid.com

3. 2012 Electricity Ten Year Statement, November 2012, www.nationalgrid.com

4. TNEI/PPA Energy, 'Offshore Transmission Coordination Project – Final Report for the Asset Delivery Workstream', December 2011

5. ENTSO-E (European Network of Transmission System Operators for Electricity) 'Offshore transmission technology', November 2011

6. OffshoreGrid, 'Offshore electricity infrastructure in Europe – A techno-economic assessment', Final Report, October 2011

7. CIGRE JWG B2/B4/C1.17, 'Impacts of HVDC lines on the economics of HVDC projects', CIGRE Ref. 388, August 2009

8. CIGRE B4.46, 'Voltage source converter (VSC) HVDC for power transmission – Economic aspects and comparison with other a.c. and d.c. technologies', CIGRE Ref. 492, April 2012

9. CIGRE B4.52, 'HVDC grid feasibility study', CIGRE Ref. 533, April 2013

10. RenewablesUK, Offshore Wind: Forecasts of future costs and benefits, June 2011

    http://www.ppaenergy.co.uk/web-resources/resources/710645de357.pdf

11. Marketsandmarkets, HVDC Transmission Market - By Technology (LCC/VSC), Configuration (Back To Back, Monopolar, Bipolar, Multi-Terminal), Power Rating (Below 500 MW, 501 MW - 999 MW, 1000 MW - 2000 MW & Above 2000 MW), Application, Component & Geography (2013 - 2018)http://www.marketsandmarkets.com/Market-Reports/hvdc-grid-market-1225.html

5 Staged Construction of HVDC Transmission Systems

5.1 Introduction

HVDC transmission lends itself to construction in discrete stages. Staged construction allows investment to be better phased in accordance with the system requirements at the time of investment. The staged construction of HVDC transmission systems is described in CIGRE Ref. 186 [1]. The present chapter introduces transmission configurations for VSC HVDC schemes and describes how the scheme may be constructed in stages.

5.2 HVDC Transmission Configurations

The choice of transmission configuration is a key factor in enabling an HVDC transmission system to be constructed in stages. The transmission configuration also has major impacts on the loss of power transmission during outages of converters and d.c. circuit conductors and on the capital and operating costs of the scheme. Possible configurations for VSC HVDC transmission are described in PD IEC/TR 62543 [2]. Configurations for HVDC grids are discussed in CIGRE Ref. 533 [3].

5.2.1 Monopolar configurations

A monopolar configuration uses a single converter unit at each end of the HVDC system. Symmetrical and asymmetrical monopolar configurations exist.

The symmetrical monopole configuration is shown in Figure 1. The voltages at the d.c. terminals are equal magnitude and opposite polarity. The mid-point of the d.c. circuit is earthed. No current flows through earth under normal operating conditions. Most VSC HVDC schemes installed to date are of symmetrical monopolar configuration.

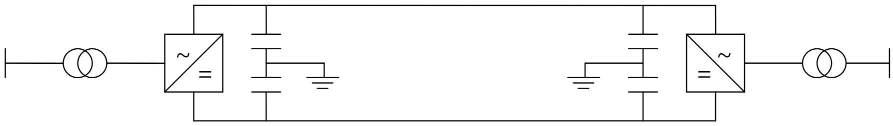


Figure 1: Symmetrical monopole

The asymmetrical monopole configuration is shown in Figures 2 and 3. One side of the d.c. circuit is at high voltage and the other side is earthed. The return circuit may either be a metallic return, as shown in Figure 2, or an earth or sea return, as shown in Figure 3. The use of an earth or sea return may yield savings on cable costs, but is unacceptable in many parts of the world due to environmental concerns.

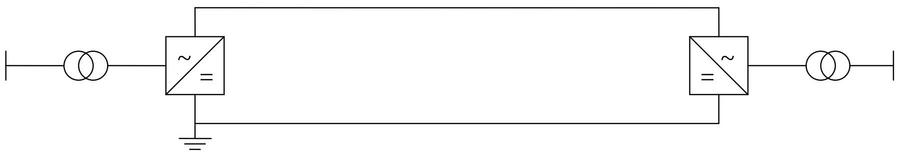


Figure 2: Asymmetrical monopole with metallic return

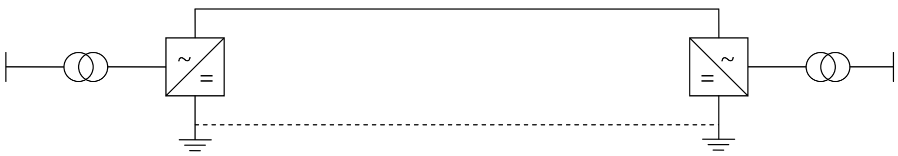


Figure 3: Asymmetrical monopole with earth or sea return

Where a monopolar configuration is used, an outage of either a converter or a d.c. circuit conductor will cause the loss of all power transmission for the duration of the outage.

5.2.2 Bipolar configurations

The basic bipolar configuration is shown in Figure 4. The bipolar configuration consists of two asymmetrical monopoles of opposite polarity with respect to earth. In normal operation, the pole voltages and currents are maintained in balance by the control system.

Switchgear is usually provided to allow the HVDC system to be reconfigured as a monopole, allowing power transmission to continue at a reduced level during an outage of a converter. Following reconfiguration, the healthy pole operates as an asymmetrical monopole using the circuit of the pole that is on outage as the return conductor. Switching for reconfiguration is performed with the d.c. circuit de-energised and all power transmission is interrupted temporarily while re-configuration takes place.

In the event of an outage of a d.c. circuit conductor, all power transmission is lost.

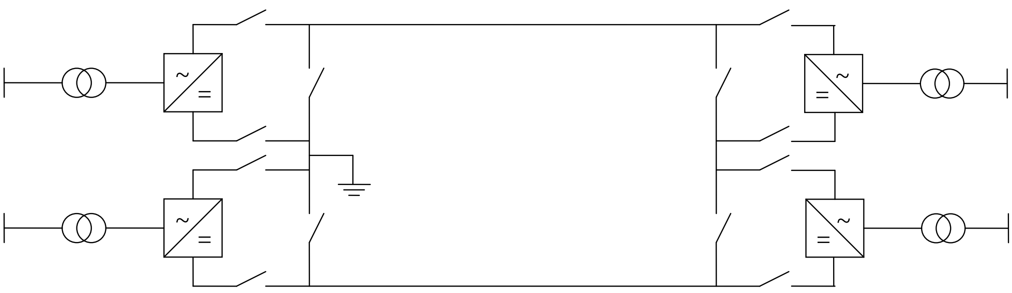


Figure 4: Bipole configuration

A metallic return, as shown in Figure 5, may be provided. The return circuit allows the HVDC system to be reconfigured for monopole operation without interrupting power transmission through the healthy pole. Power transmission may continue at a reduced level during an outage of either a converter or a d.c. circuit conductor.

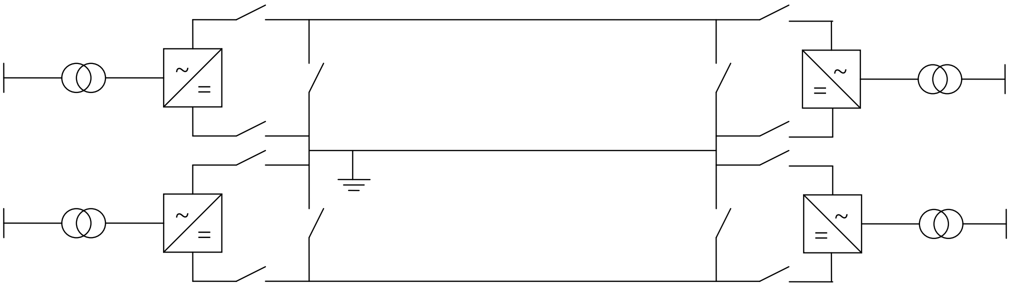


Figure 5: Bipole with metallic return

In some circumstances, the provision of a metallic return will be advantageous in allowing the limits on loss of infeed permitted by the planning standards to be complied with.

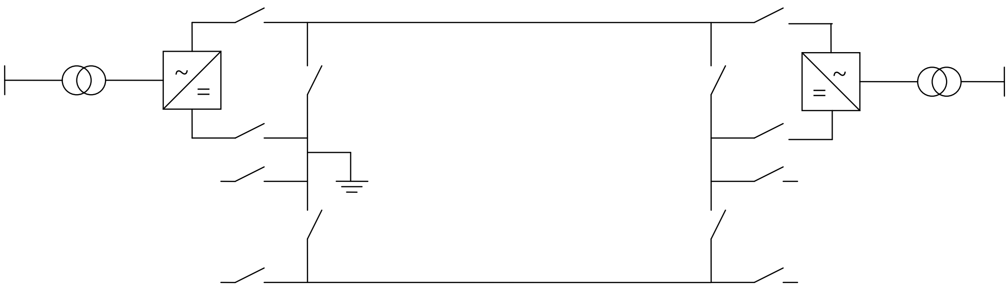
Although only carrying a current while the system is operating as a monopole, the metallic return requires a current rating equal to that of the pole conductors. As in the case of the asymmetrical monopole, an earth or sea return might, in principle, be used as an alternative to the metallic return, but this is unacceptable in many parts of the world. Where an earth return is used, a metallic return transfer breaker may be provided to transfer the d.c. current from the earth return to the conductor of the pole that is on outage following reconfiguration of the d.c. circuit.

The bipolar configuration may be used with VSC HVDC systems and is a common configuration for LCC systems.

5.3 Staged construction

The most common staging in d.c. transmission is the initial construction of a monopole and subsequent extension to a bipole [1]. The staged construction of a bipole is illustrated in Figure 6. The system is initially constructed as an asymmetrical monopole using the conductor of the future pole as metallic return.

Stage 1



Stage 2

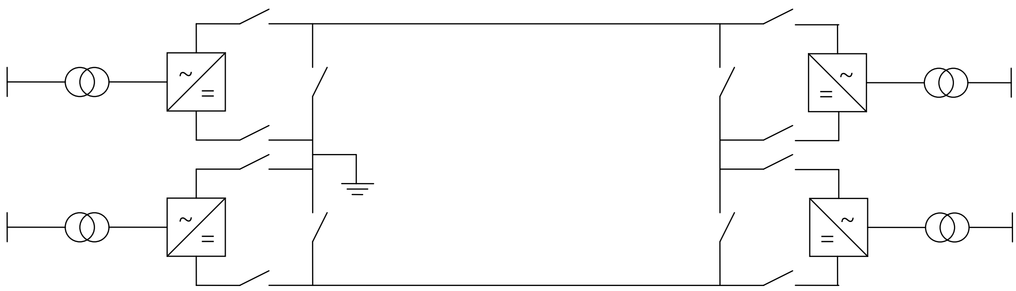
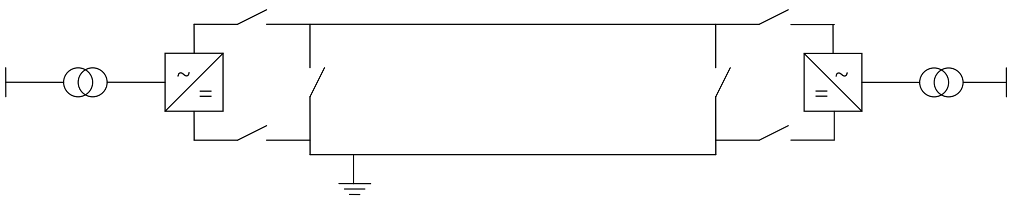


Figure 6: Staged construction of bipole

The staged construction of a bipole with metallic return is illustrated in Figure 8. The metallic return is installed during the initial stage and the conductor of the future pole is installed during the second stage of construction.

Stage 1



Stage 2

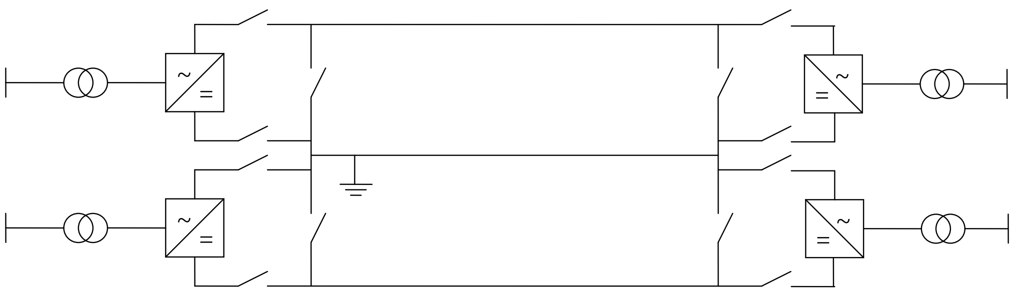


Figure 8: Staged construction of a bipole with metallic return

The potential requirement to extend an HVDC link to form a bipole in a future second stage of construction must be taken into account when the original scheme is designed. If insufficient provision is made, connection of the second stage may be difficult or even impossible. Space must be available for the future converters and, depending on the configuration, for a future cable. For offshore installation, it may be beneficial if infrastructure such as additional J-tubes and switchgear bays are provided when the initial installation is constructed. Consideration will need to be given to the outages of the system that is in service for connection and commissioning of the second stage.

Where the potential requirement for future bipolar extension exists, the initial scheme must be of asymmetrical (rather than symmetrical) monopole configuration. For a given power transfer capability, the d.c. pole to earth voltage will be higher than it would have been for a symmetrical monopole configuration. The higher d.c. voltage will tend to increase the cost of the initial scheme. The overall cost of the final bipolar scheme, however, may be less than that of constructing two symmetrical monopoles in succession.

The provision of a third cable, as required by the bipole with metallic return, will significantly increase the capital cost of the second stage. It will, however, increase the reliability and availability of the final scheme, particularly in the event of a d.c. cable fault. Installation of the third cable in proximity to the two cables already in service may present difficulty.

When extending a monopole to form a bipole, the protection and control systems will need to be upgraded for bipolar operation. This may present challenges with regard to equipment compatibility and factory testing unless the contract for the extension is placed with the original supplier.

To date, few VSC HVDC schemes have been constructed in stages. Some information has, however, been reported. The first stage of the Caprivi Link Interconnector in Africa has been constructed as a 300 MW HVDC transmission line with asymmetrical monopolar converter stations [4]. The scheme has been designed for extension to a 600 MW bipolar system in a future second stage.

Skagerrak 4, a VSC link currently under construction, will constitute the fourth HVDC link between Denmark and Norway. Skagerrak 4 will operate together with the existing Skagerrak 3, which uses line commutated converters, to form a bipole [5]. The extension includes an upgrade of the control system for bipolar operation.

5.4 Conclusions

HVDC schemes may be constructed in stages to allow investment to be better matched with system requirements where the need for a higher transmission capacity at some time in the future is anticipated. The scheme may be constructed initially as an asymmetrical monopole and extended to a bipole as and when the need for a higher transmission capacity arises. The bipole may be provided with a metallic return if required, which, while increasing the cost of the second stage of construction, will increase availability particularly in the event of an outage of a d.c. circuit conductor and will restrict the loss of transmission occurring in the event of a fault or converter trip.

VSC HVDC schemes may be constructed in stages although few such schemes have been constructed so far. Examples of VSC HVDC schemes designed for staged construction are the Caprivi Link Interconnector in Africa and Skagerrak 4 in Scandinavia. Staged construction might be found to be an attractive approach in the construction of an integrated offshore transmission system.

5.5 References

1. CIGRE WG 14.20, ‘Economic assessment of HVDC links’, CIGRE Ref. 186, June 2001

2. PD IEC/TR 62543, ‘High-voltage direct current (HVDC) transmission using voltage sourced converters (VSC)’

3. CIGRE WG B4.52, ‘HVDC grid feasibility study’, CIGRE Ref. 533, April 2013

4. Magg, T, Manchen, M, Krige, E, Washborg, J, and Sundin, J, ‘Connecting networks with VSC HVDC in Africa: Caprivi Link Interconnector’, IEEE PES PowerAfrica 2012 Conference and Exposition, Johannesburg, South Africa, 9-13 July 2012

5. http://new.abb.com/systems/hvdc/references/skagerrak

6. Technology Reliability and Availability

6.1 Introduction

The aim of this chapter is to present published information on the reliability and availability of HVDC technology. This information will be used in cost benefit analysis for an integrated offshore transmission system.

Meaningful information on reliability and availability requires a sufficient level of service experience to have been accrued. Most of the data that has been collected for HVDC systems corresponds to line commutated converters (LCC) and mass impregnated (MI) cables. Less experience exists with voltage sourced converters (VSC) and extruded cables and little data for these is available in the literature.

Generally, the user specifies the reliability and availability requirements for a given HVDC system in his specification and the supplier designs the solution in order to achieve the specified performance [1]. The information presented in this chapter concerns the reliability and availability that has been achieved in service.

The figures presented in this chapter are based on the HVDC system reliability surveys carried out annually by CIGRE B4 AG 4 and reported every two years at the CIGRE Paris session. The data is reported in accordance with a protocol [2] developed by AG 4. Energy Unavailability (EU) is defined in the protocol as 'a measure of the energy which could not have been transmitted due to outages'. Energy Unavailability includes Forced Energy Unavailability (FEU) and Scheduled Energy Unavailability (SEU). In the present chapter, greater emphasis is given to FEU than SEU since scheduled outages may be planned for periods when unavailability of the HVDC system is acceptable. The protocol also defines the concept of Equivalent Outage Hours (EOH) as 'the sum of equivalent outage durations within the reporting period'.

The tables presented in this chapter provide the reliability and availability data of various HVDC components. The data presented includes energy unavailability, failure rate and mean time to repair.

6.2 HVDC Converter

Table 1 shows the average FEU for HVDC converters from the last four CIGRE reliability survey reports [3, 4, 5, 6]. The data has been classified according to the major equipment category as follows:

AC and auxiliary equipment	AC-E
Converter transformer	Conv Tx
Valves	V
Control and protection	C&P
DC equipment	DC-E
Other	O

Data on transmission lines or cables reported in the CIGRE surveys has been excluded from the data presented in Table 1.

Table 1 Average FEU for HVDC converters

	2003-04[3]	**2005-06**[4]	**2007-08**[5]	**2009-10**[6]	**Overall 1983 – 2008**[**Error! Bookmark not defined.**]
Average of System FEU Hours / Station / year	177.3	266.3	170.2	271.7	169.4
AC – E	10.7%	3.0%	4.1%	4.1%	64.2%
Conv.Tx	82.7%	80.9%	82.5%	79.0%	
Valves	0.6%	11.2%	1.8%	3.3%	11.5%
C&P	3.7%	2.2%	3.3%	8.9%	8.0%
DC – E	2.1%	2.1%	8.0%	4.7%	15.4%
Others	0.3%	0.5%	0.3%	0.9%	0.9%

From Table 1, it can be seen that converter transformer failures account for a large proportion of FEU for a.c. Equipment. Table 2 gives values of average system FEU and system EOH with converter transformer failures both included and excluded from the analysis.

Table 2 Average FEU for HVDC converters with and without converter transformer data

	2005-06	**2007-08**	**2009-10**
System FEU Including Transformer %	3.04%	1.94%	3.1%
System FEU Excluding Transformer %	0.58%	0.34%	0.65%
System EOH Including Transformer (hours)	266.3	170.2	271.7
System EOH Excluding Transformer (hours)	50.8	29.8	57.1

The data reported in the surveys is for HVDC systems which are either back-to-back or point-to-point and hence comprise two HVDC converter stations. The FEU for a single HVDC converter may be obtained by assuming that it accounts for 50% of the system FEU. Values of HVDC converter FEU excluding converter transformers are given in Table 3.

Table 3 HVDC Converter FEU

		HVDC LCC System	**Single Converter Station**
2005-06[Error! Bookmark not defined.]	FEU %	0.58%	0.29%
	MTTR (hrs)	50.8	25.4
2007-08[Error! Bookmark not defined.]	FEU %	0.34%	0.17%
	MTTR (hrs)	29.8	14.9
2009-10[Error! Bookmark not defined.]	FEU %	0.65%	0.325%
	MTTR (hrs)	57.1	28.55

VSC HVDC systems have not reported reliability performance data to CIGRE Advisory Group B4.04 to date and published data on the performance of these systems is limited. However, some data on the operation of the Cross Sound Cable project and the Murraylink project have been published [7]. Table 4 shows the reported average FEU for the two systems for seven years operation from 2003 through to 2009.

Table 4 Reliability Performance of two VSC-HVDC Systems

	Average FEU %
Cross Sound Cable (330MW, ±150kV)	1.16
Murraylink (220MW, ±150kV)	2.35

The development in the capability of VSC HVDC technology have increased since the installation of these two VSC HVDC systems, but these developments have yet to provide service experience.

6.2.1 Converter Transformer

Given that converter transformer failures account for a large portion of converter FEU, CIGRE set up a Joint Task Force [8], [9] to report on converter transformer failures. The report [9**Error! Bookmark not defined.**] addresses converter transformer failures in the period 1972 to 2008. It classifies the converter transformer failure areas into bushings, valve winding, a.c. winding, static shields, load tap changers, core and magnetic shields and internal connections.

The report [9] also categorised failures as actual failures or preventive failures. An actual failure was defined as a failure where removal of a unit from service was required due to the damage of the active part. A preventive failure was defined as a failure where the unit did not actually fail but was taken out of service to repair active parts following diagnostic testing such as dissolved gas-in-oil analysis (DGA), high insulation power factor, or failure of similar unit(s). [9]

Converter Transformer failure rate is based on the ratio between the total number of units failed and the total number of units in service in a number of years. Figure 1, taken from [9**Error! Bookmark not defined.**], shows the converter transformer failure rate against year of commissioning. The figure shows an increase in failure rate for preventive failures while the total failure rate reduces. This trend is due to:

a) Modern transformers are now more closely monitored
b) Most of the systems are designed with spare transformers being readily available: statistics in the reports shows that converter transformer failure rate has improved
c) Implementation of the modified IEC Standard (61378-2) issued in 2001

These developments have improved the failure rate of the converter transformers to about 0.02 per year in the period of 2006 - 2008

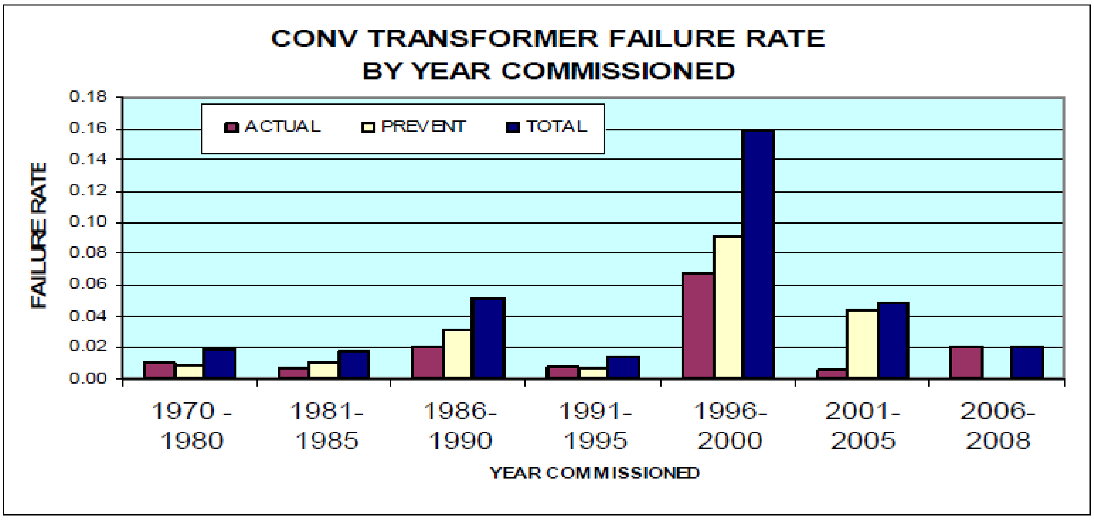


Figure 1 Converter Transformer failure rate by year of commissioning

Reported converter transformer reliability mainly focuses on LCC HVDC schemes. It is assumed that VSC HVDC schemes will utilise conventional HVAC transformers, therefore the availability and reliability of VSC transformers will be the same as HVAC transformers.

Converter Transformer replacement with Spare

The provision of spare transformer at site minimises the outage time in the event of a converter transformer failure. Table 4 shows the reported [**Error! Bookmark not defined.**] outage hours for transformer replacement when a spare transformer was available on site.

Table 4: Average transformer replacement time

Projects	No of Units Replaced with Spare	Outage Time (h)
Gui-Guang 2	1	177
Rihand-Dadri	2	39
Tian-Guang	1	49
3G-Changzhou	1	72
3G-Guangdong (	1	72
Nelson River (2006)	1	67
3G-Guang (2007)	1	72
Total	**8**	**548**
Average Transformer replacement time		**68.5**

In an offshore environment, transformer replacement times are subject to a number of factors that can lead to a significant increase in replacement time. These include the availability of a spare transformer at the platform, tools, availability of vessel (if spare transformer is not at site) and weather conditions.

6.3 HVDC Cable

The primary source of cable reliability data is a survey reported in CIGRE brochure 379 [10]. The data presented in the brochure is related to the installed quantities of underground and submarine cable systems rated at 60kV and above together with the service experience and performance of existing underground and submarine cable systems rated at 60kV above. The survey is based on responses received from utilities and cable suppliers.

The survey considers a 5 year period ending December 2005 for land cables and a 15 year period ending December 2005 for submarine cables.

The survey identified more than 33,000 circuit km of underground cables and approximately 7,000 circuit km of submarine cable system in service at the end of December 2005.

49 faults were reported on submarine cables in which 4 of it were related to a.c. XLPE cable and 18 were related to d.c. MI. The faults reported are mainly external faults, with immediate breakdown or an unplanned outage of the cable system.

Tables 5 and 6 provide a summary of failure rates for submarine d.c. MI and submarine a.c XLPE cables. The causes of failure were classified as 'internal' and 'external or unknown'. For both types of cable, all reported failures were attributed to external or unknown causes. Reported a.c. XLPE cables faults occurred on voltages below 220kV as there were cables beyond this range.

Table 5: DC Submarine cable failure rates (fail/year cct.km)

	DC - MI Cables		
	60 – 219 kV	**220 – 500 kV**	**All Voltages**
Internal	0.00000	0.00000	0.00000
External or Unknown	0.001336	0.000998	0.001114
Total	0.001336	0.000998	0.001114

Table 6: AC Submarine cable failure rates (fail/year cct.km)

	AC - XLPE cables		
	60 – 219 kV	**220 – 500 kV**	**All Voltages kV**
Internal	0.00000	N/A	0.00000
External or Unknown	0.000705	N/A	0.000705
Total	0.000705	N/A	0.000705

Since all causes of failure were external or unknown, it is suggested that the failure rates reported for d.c MI cables could be used for d.c extruded cables. This is based on the following:

- External faults are not generally related to insulation type since the reported d.c. MI cable external cable faults were caused by activities such as trawling, anchoring and excavation
- No internal faults were reported on either the a.c. extruded or d.c. MI hence we can assume the same for d.c. extruded
- Installed capacity of submarine d.c. MI in the reported period is greater than installed submarine a.c. extruded
- Lack of published data for extruded submarine a.c. cables
- Reported a.c. extruded cable failure rated 220kV and below.

Excluding the extremes and unknown faults, the average reported repair time of submarine cables is approximately 60 days. However, repair times for submarine cables are subject to a number of factors which can lead to significant increase in repair time. These factors include weather conditions, vessel availability and spares availability. Long outage times were related more to location of cable installation and type of cable than voltage level.

6.4 CONCLUSIONS

Reliability and availability data based on published information have been collected for use in cost benefit analysis for an integrated offshore transmission system. The recommended data are summarised in Table 7 for converter stations, in Table 8 for converter transformers and in Table 9 and for cables.

The data presented in Table 7 for converter reliability is based on the CIGRE survey for the years 2009 – 2010 [6**Error! Bookmark not defined.**] since it is the most recent survey and therefore most representative of present technology.

Table 7 Summary of Converter Reliability

	FEU (%)	Mean time to repair (hours)
Converter	0.325	28.55

Operational experience has only been reported for two VSC HVDC projects. The reported data is not considered sufficient to provide reliability and availability figures that are representative of VSC HVDC systems in general.

The converter transformer reliability data in Table 8 is based on results reported by the CIGRE JWG A2/B4.28 [9]. Reliability data of converter transformers commissioned after 2006 has been selected since this is most representative of present technology.

Table 8 Summary of Converter Transformer Reliability

	Failure Rate (per year)	Mean time to repair (hours)
Converter Transformer	0.02	68.5

The d.c. cable data in Table 9 is based on the survey reported by CIGRE WG B1.10 [10]. In the present work, it is assumed that d.c. extruded cable will have same failure rate as a.c. extruded cable given that the reported a.c. extruded cable failures were all external failures.

Table 9 Summary of HVDC Cable Reliability

	Failure Rate (per circuit km year)	Mean time to repair (days)
DC MI Cable	0.001114	60
DC XLPE Cable	0.000705	60

In recent years, experience with both VSC HVDC converters and d.c. extruded cables has increased, although the service experience with these technologies has yet to be published. In the absence of published data, assumptions on reliability and availability can be made based on experience with LCC HVDC converters and MI d.c. cable. Meanwhile, there is a pressing need for published data for VSC HVDC converters and d.c. extruded cables.

6.5 References

[1] BS 60919-1 Performance of high-voltage direct current (HVDC) systems with line-commutated converters

[2] 346 Protocol for Reporting the Operational Performance of HVDC Transmission Systems

[3] B4_202_2006 Survey of the reliability of HVDC systems throughout the world during 2003 – 2004

[4] B4_119_2008 A survey of the reliability of HVDC systems throughout the world during 2005 – 2006

[5] B4_209_2010 A survey of the reliability of HVDC systems throughout the world during 2007 – 2008

[6] B4_113_2012 A survey of the reliability of HVDC systems throughout the world during 2009 – 2010

[7] Dodds, S; Railing, B; Akman, K.; Jacobson, B.; Worzyk, T.; Nisson, B.; HVDC VSC (HVDC Light) Transmission - Operating Experiences, B4-203, CIGRE 2010

[8] Joint Task Force B4.04 /A2-1 “Analysis of HVDC Thyristor Converter Transformer Performance” CIGRE Publication 240, February 2004

[9] Joint Working Group A2/B4.28 “HVDC Converter Transformers” CIGRE Publication 406, February 2010

[10] B1.10 Cigre Brochure 379 “Update of Service Experience of HV Underground and Submarine Cable Systems”

7 PROTECTION STRATEGY

7.1 Introduction

Suitable protection strategies for point-to-point offshore wind farm connections have been well established in the course of a number of projects around the world [1]. Such projects have utilised standard practices for both a.c. (Alternating current) and d.c. (Direct current) applications respectively. The present chapter considers the challenge of devising a suitable protection system for such a network within the scope of the integrated offshore transmission project.

Firstly, a brief introduction to the functional and performance requirements of a protection system is described. This is followed by a description of possible protection strategies using a.c. and d.c. circuit breakers respectively.

Five Generic scenarios, one using d.c. circuit breakers, are analysed in turn for faults at different locations. The sequence of protection actions following the detection of the fault are explained.

For a.c. protection systems the total duration of a fault can have a significant affect on the stability and security of the power system. If the fault is not cleared within a specific time, otherwise known as the critical fault clearing time, the power system will lose the angular stability

For d.c. protection systems the clearance of a fault on the d.c. side may be much faster compared to that on the a.c. side. Limiting the fast rise in d.c. current, as well as preventing d.c. voltage collapse is the key drivers for the d.c. protection systems [2].

The ability of a converter station to control fault currents is an area still under study [2]. Line Commutated Converter (LCC) as well as Voltage Source Converter (VSC) Full Bridge (FB) stations can have ability to control or block fault currents, while a VSC Half Bridge (HB) combined with fast a.c. or d.c. side circuit breakers can behave similar to the VSC Full bridge [2].

The earthing of the HVDC system plays a key role in the formation and distribution of short-circuit currents, and therefore can have a large influence on the protection system to successfully detect and clear earth faults [2].

7.1.1 Key Functional and Performance Requirements

Each HVDC converter station should be equipped with a protection system which must operate correctly under both normal and abnormal conditions. The HVDC system should remain stable in all situations and the system must be self-protecting with and without inter-station communications in service. The protection systems for all converter stations of a HVDC system should be interoperable.

The protection system should have full redundancy in all vital parts. The protection for an HVDC converter station should comprise protection functions related to Harmonic Filter(s), Converter Transformers(s), Poles(s)/Converter(s), d.c. busbar(s)/line(s) and a.c. busbar(s).

The HVDC protection system should be divided into a number of separately protected and overlapping zones. A protection function should only operate upon a specific fault within a designated zone and must remain stable to any faults external to the relevant zone.

Protection and control systems should be as independent as possible. Each of the protection systems should always remain active and be powered by separate, independent supplies to ensure satisfactory operation in the event of the loss of one supply.

Each protective zone should be protected by two main protection functions and one back-up protection function, preferably using different protection principles. Where it is not possible to use different protection principles, duplicated protections should be used.

The protection functions of the HVDC system should be coordinated with those of the connected a.c. network.

The protection system should be designed to ensure that no single credible malfunction shall cause the total failure of the HVDC system.

A typical protection arrangement for a HVDC converter station is shown in the figure below.

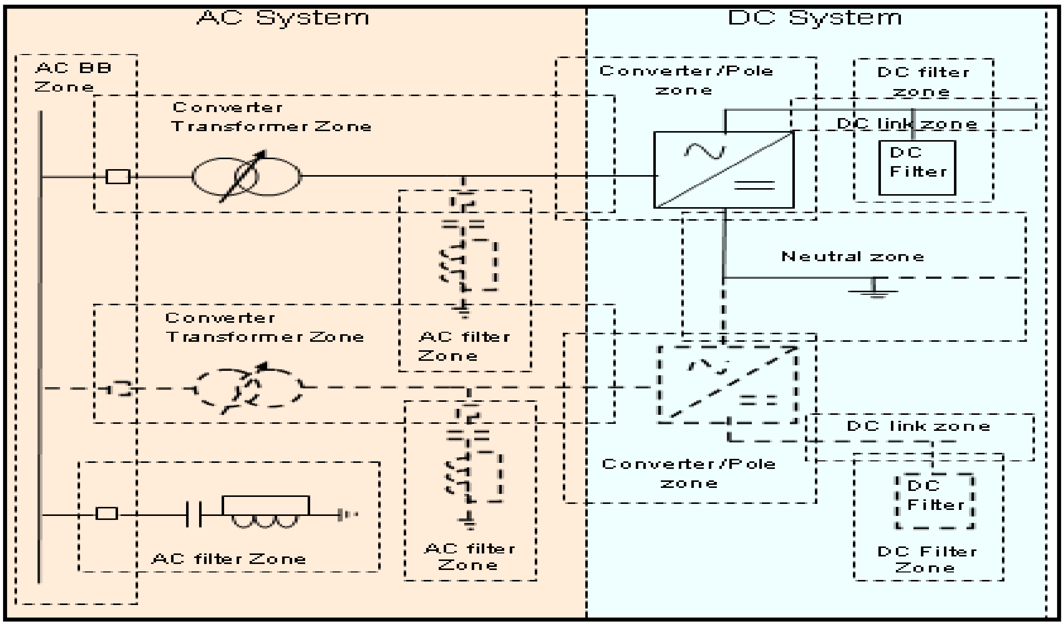


Figure 2*:* Example of HVDC Protection zones

Generally-speaking there are two protection strategies for managing faults within a DC network or a Line: Using a.c. Circuit Breakers and using d.c. Circuit Breakers.

7.2 Protection Strategy Using AC Circuit Breakers

In a.c. systems, it is standard practice to clear a fault by sending trip commands to the relevant a.c. circuit-breakers.

LCC HVDC converters and some types of VSC HVDC converters have the ability to block the infeed of fault current from a d.c. fault, allowing the fault to be cleared by appropriate control or switching actions [3].

For the HVDC converters that do not have the ability to block the infeed of fault current, the opening of the a.c. circuit breaker at each d.c converter to clear a d.c. fault is one of the strategies for a d.c. protection system.

The faults on the offshore a.c. network and windfarm generators are expected to be detected and cleared by the dedicated offshore windfarm protection systems, hence not within the scope of discussion in this report.

7.2.1 Scenario 1

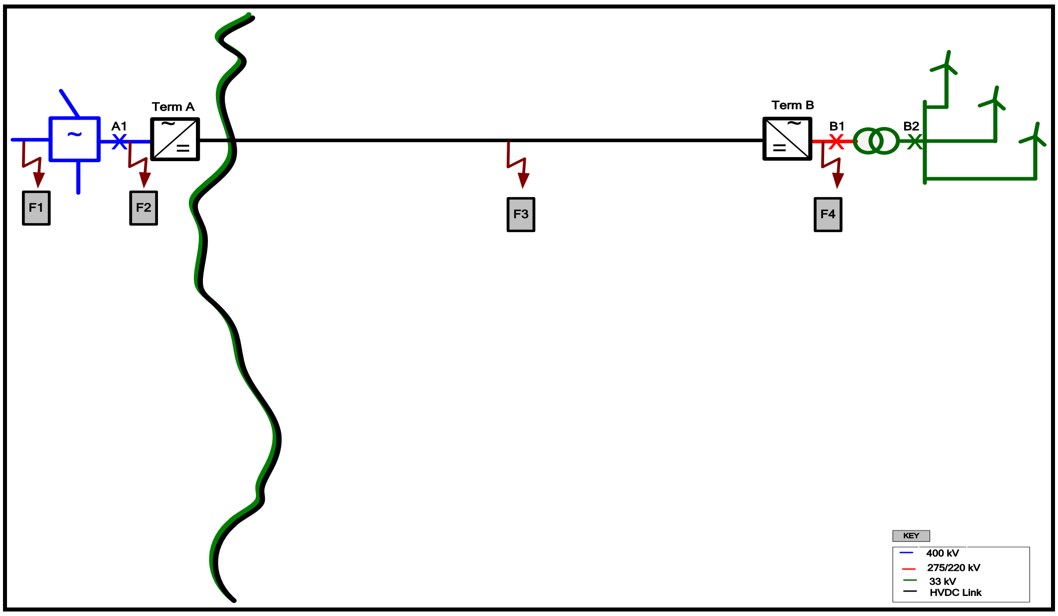


Figure 3: Basic point to point HVDC link

<u>Protection Strategy for Scenario 1</u>

For scenario 1 above, the protection strategy for a point-to-point wind farm connection has already been well established in practice [4],[5]. For any fault at location F1, the wind farm must stay connected to the offshore system for the total duration of the fault (fault ride through), until it has been successfully detected and cleared by the onshore a.c. protection systems.

For a fault at other position F2, F3 and F4 has to be cleared by tripping the a.c. CBs at both end of the d.c. link, and will result in the removal of both the d.c. link and wind farm from the system.

Fault Analysis for Scenario 1

Faults (Onshore)

For a fault on the a.c. network, such as that at F1, the local a.c. protection system will trip associated circuits on shore to clear the fault.

For a fault at F2 between the onshore a.c. circuit breaker A1 and d.c. converter at terminal A, the HVDC converter station protection system at Terminal A will be required to:

1. Detect the fault.

2. Send a blocking signal to the onshore converter at terminal A

3. Trip both the onshore a.c. circuit breaker A1 and offshore a.c. circuit breaker B1 to clear the fault.

Fault (DC Cable)

For a fault at F3 on the grid side of the converter, the HVDC protection system will be required to:

1. detect the fault,

2. Issue blocking commands to both the onshore d.c. Converter at terminal A and offshore d.c. converter at terminal B.

3. Trip both the a.c. Circuit Breakers A1 and B1 to clear the fault

Faults (Offshore Converter)

For a fault at position F4 between the offshore a.c. circuit breaker B1 and the d.c. converter at terminal B, the protection system at converter station Terminal B will be required to

1. Detect the fault.

2. Issue a blocking command to the d.c. converter at terminal B

3. Trip the a.c. circuit breaker B1 to clear the fault.

7.2.2 Scenario 2

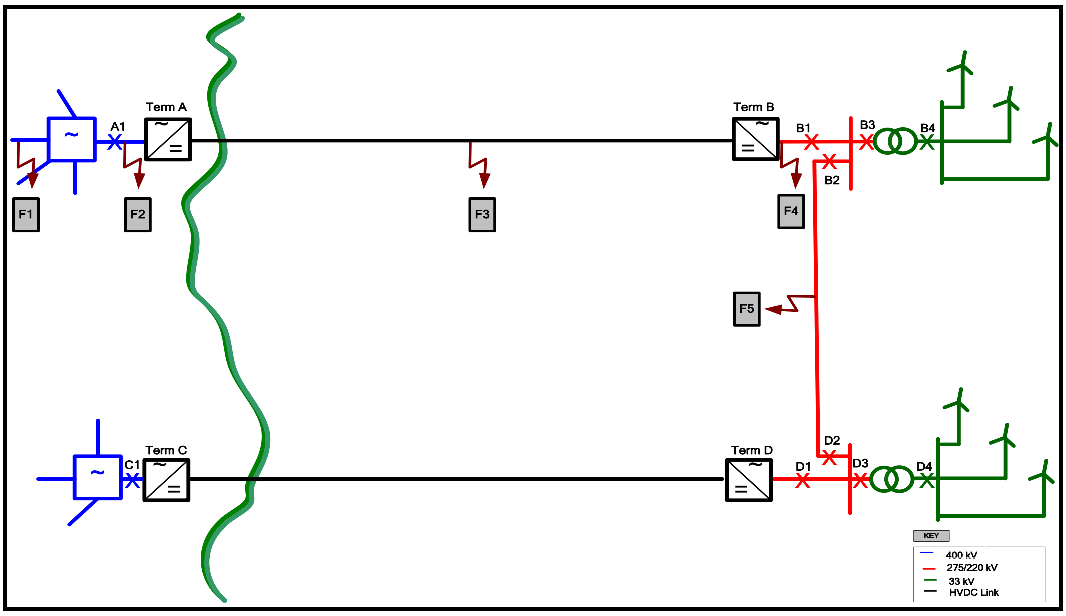


Figure 4: Radial d.c. links with a.c. Interconnection

<u>Protection Strategy for Scenario 2</u>

For any fault at location F1, the wind farm must stay connected to the offshore system for the total duration of the fault (fault ride through), until it has been successfully detected and cleared by the onshore a.c. protection system.

For a fault at position F2, F3 and F4 has to be cleared by tripping a.c. CB A1, B1 which will result in the removal of the d.c. link between terminals A and B from the system. With the addition of the a.c. interconnection between the two offshore wind farms it will be possible to keep the offshore wind farm located at terminal B in-service.

For a fault at F5, due to a cable connection, only the a.c. interconnection between the two wind farms needs to be tripped by opening a.c. CB B2 and D2. This strategy will result in both the wind farms and d.c. links operating as separate radial connections to the onshore system.

<u>Fault Analysis for Scenario 2</u>

Faults (Onshore)

For a fault at F2 between the onshore a.c. circuit breaker A1 and d.c. converter at terminal A, the protection system at converter station term A will be required to:

1. Detect the fault.
2. Send a blocking signal to the onshore converter at terminal A

3. Trip both the onshore a.c. circuit breaker A1 and offshore a.c. circuit breaker B1 to clear the fault.

Fault (DC Cable)

For a fault at F3 on the grid side of the converter, the HVDC protection system will be required to:

1. Detect the fault,
2. Issue blocking commands to both the onshore d.c. Converter at terminal A and offshore d.c. converter at terminal B.
3. Trip both a.c. Circuit Breakers A1 and B1 to clear the fault

Faults (Offshore Converter)

For a fault at position F4 between the offshore a.c. circuit breaker B1 and the d.c. converter at terminal B, the protection system at converter station Term B will be required to

1. Detect the fault.
2. Issue a blocking command to the d.c. converter at terminal B
3. Trip the a.c. circuit breaker B1 and A1 to clear the fault.

Faults (AC interconnection)

For a fault at position F5 on the a.c. interconnection between the two offshore wind farms the a.c. cable protection system will be required to:

1. Detect the fault.
2. Trip both a.c. circuit breakers B2 and D2 to clear the fault

7.2.3 Scenario 3

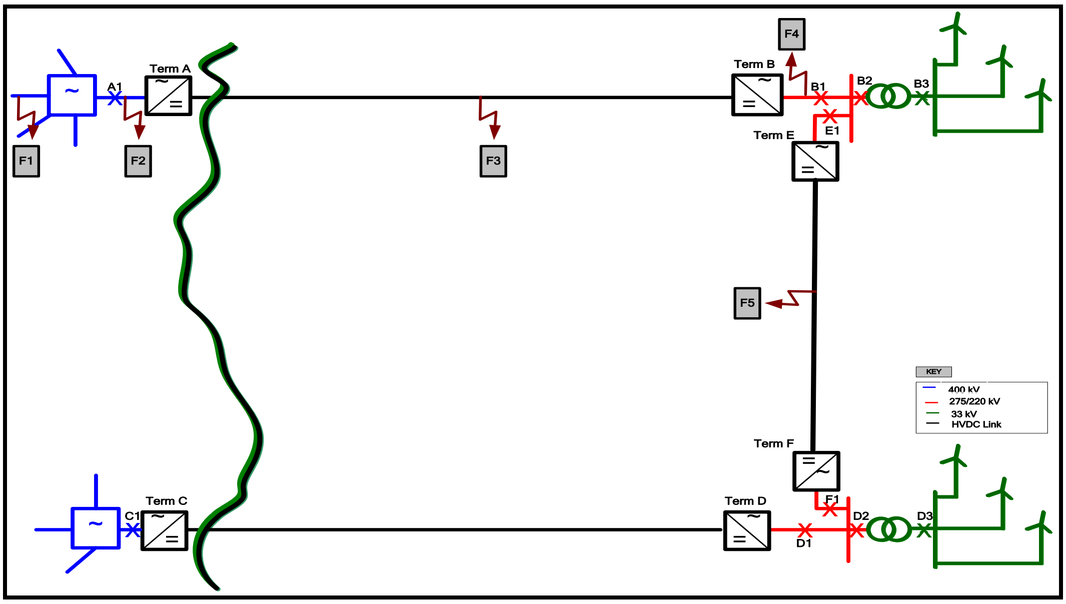


Figure 5: Interconnection via Point-to-point HVDC Link

<u>Protection Strategy for Scenario 3</u>

For any fault at location F1, the wind farm must stay connected to the offshore system for the total duration of the fault (fault ride through), until it has been successfully detected and cleared by the onshore a.c. protection system.

For a fault at position F2, F3 and F4 has to be cleared by tripping a.c. CB A1 and B1, which will result in the removal of the d.c. link between terminals A and B from the system. With the addition of the d.c. interconnection between the two offshore wind farms it will be possible to keep the offshore wind farm located at terminal B in-service.

For a fault at F5, due to a cable connection, only the d.c. interconnection between the two wind farms will need to tripped to clear the fault. This strategy will result in both the wind farms and d.c. links operating as separate radial connections to the onshore system, as was the case with scenario 2.

<u>Fault Analysis for Scenario 3</u>

The protection operation sequence for the faults on the location at F1 – F5 are the same as Scenario 2.

7.2.4 Scenario 4

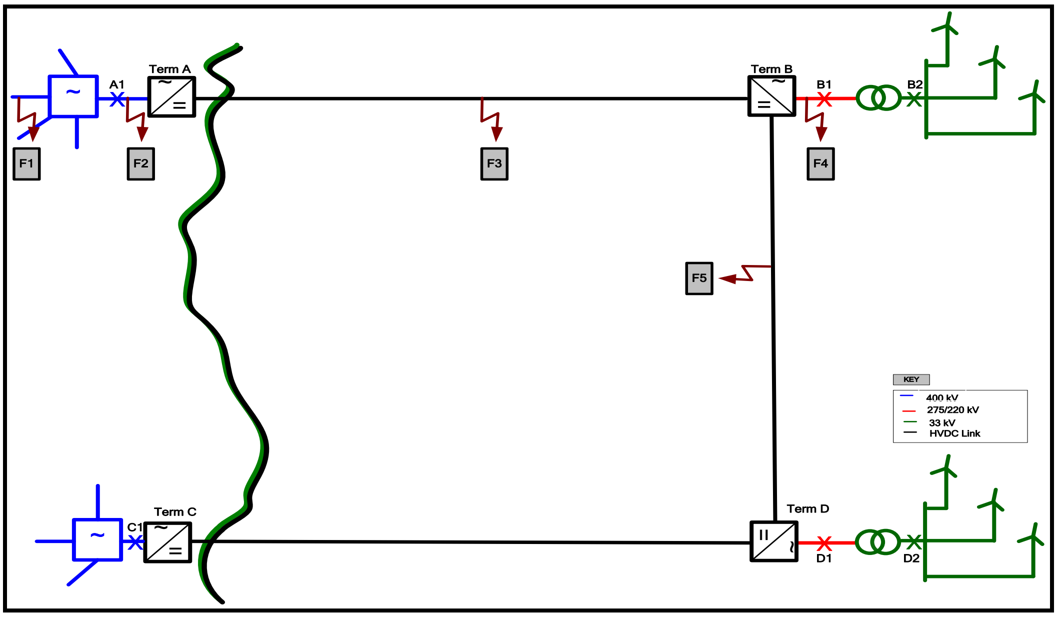


Figure 6: Interconnection with Multi-terminal HVDC Grid

Protection Strategy for Scenario 4

For any fault at location F1, the wind farm must stay connected to the offshore system for the total duration of the fault (fault ride through), until it has been successfully detected and cleared by the onshore a.c. protection system.

For a fault at position F2 – F5 has to be cleared by tripping all the a.c. CB A1,B1, C1 and D1, will result in the removal of the whole d.c. system and power transfer will be stopped. Once the fault has been successfully cleared and the faulty section isolated, the system may be restarted and power transfer can recommence.

Fault Analysis for Scenario 4

Faults (Onshore)

For a fault at F2 – F5 the HVDC protection system will be required to:

1. Detect the fault.
2. Send a blocking signal to the onshore converter at terminal A
3. Trip all the a.c. circuit breakers

7.3 Protection Strategy Using d.c. Circuit Breakers

With the inclusion of d.c. circuit breakers in a power system, the protection strategy will be different from that when conventional a.c. circuit breakers are utilised for fault clearing purposes. Due to the much quicker operating time of the d.c. circuit breaker [6], clearance of the fault can be achieved much faster compared to the fault clearing strategy of the a.c. circuit breaker. This also ensures that under the occurrence of a d.c. fault, only the faulty section is isolated and does not result in the loss of the whole power system.

One of main aims of the protection strategy is to stop the fault current from rising too high to prevent the maximum rating of the d.c. circuit breaker from being exceeded [7]. If this is not achieved then this can result in physical damage to the circuit breaker. The design of the series reactor to help limit the fault current plays a crucial role in this particular protection strategy [7].

The other aim is to help prevent the d.c. network from possible voltage collapse under a d.c. fault condition. The speed of operation of the d.c. protection is critical to prevent the above situations from occurring and requires further investigation [7]

One advantage of employing d.c. Circuit Breakers is that in the event of a one end of a d.c. link being tripped, the 'STATCOM' functionality can still be utilised on the Converters due to no blocking signal or a.c. Circuit Breaker tripping being required. Hence the voltage of either the onshore a.c. network or offshore a.c. island point of common coupling maybe supported during the fault isolation process.

7.3.1 Scenario 5

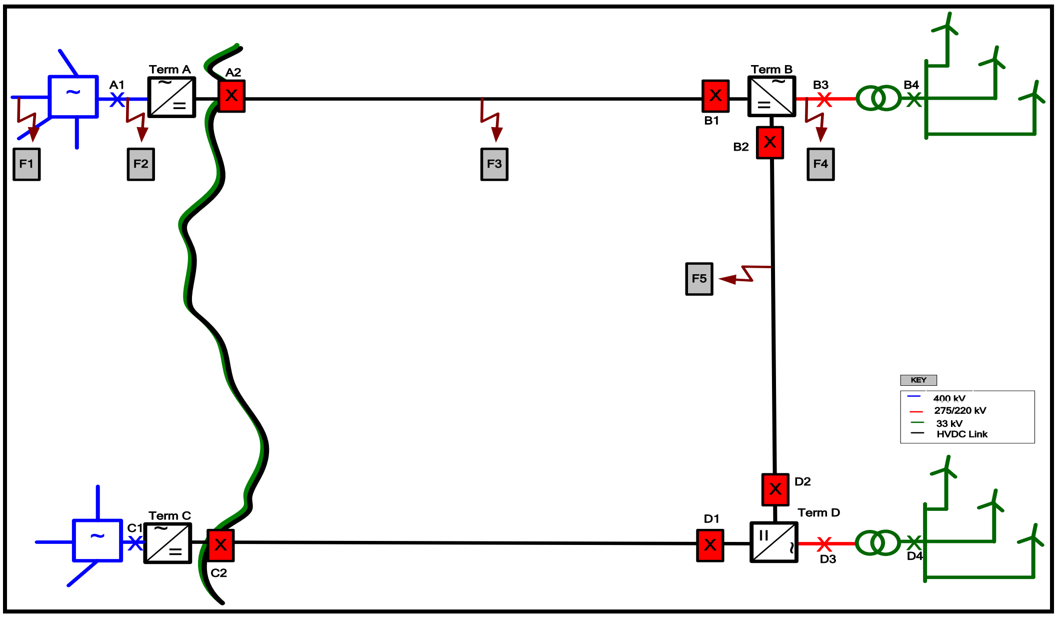


Figure 7: Interconnection with Multi-terminal Grid Utilising d.c. Circuit Breakers

<u>Protection Strategy for Scenario 5</u>

For any fault at location F1, the wind farm must stay connected to the offshore system for the total duration of the fault (fault ride through), until it has been successfully detected and cleared by the onshore a.c. protection system.

For a fault at position F2, it will be cleared by tripping a.c. CB A1 and d.c. CB A2, which will result in the removal of the onshore d.c. converter at terminal A from the system.

To clear a fault on the d.c. cable at F3 and F5, it only needs to trip the associated d.c. link by opening the two d.c. CBs at each end of the link. Other healthy part of d.c. network will remain in service.

The protection strategy to clear a fault at F4 will be very similar to that previously described for a fault at F2 and will result in the removal of the d.c. converter at terminal B from the system.

<u>Fault Analysis for Scenario 5</u>

Faults (Onshore)

For a fault at F2 between the onshore a.c. circuit breaker A1 and d.c. converter at terminal A, the a.c. protection system will be required to:

1. Detect the fault.
2. Send a blocking signal to the onshore converter at terminal A
3. Trip the onshore a.c. circuit breaker A1 and d.c. circuit breaker A2

Fault (DC Cable)

For a fault at either F3 on the grid side of the onshore converter, or F5 on d.c. cable between terminals B and D the HVDC protection system will be required to:

1. Detect the fault.
2. Trip both d.c. circuit breakers A2 and B1 to clear the fault at F3
3. Trip both d.c. circuit breakers B2 and D2 to clear the fault at F5.

Faults (Offshore Converter)

For a fault at position F4 between the offshore a.c. circuit breaker B1 and the d.c. converter at terminal B, the a.c. protection system will be required to:

1. Detect the fault.
2. Issue a blocking command to the d.c. converter at terminal B.
3. Trip the a.c. circuit breaker B1
4. trip both d.c. Circuit Breakers B2 and D2

7.4 Conclusion

Both the functional and performance requirements expected of a protection system, suitable for such an application as the IOTP(E) has been covered. Faults occurring at different locations on five generic network scenarios have been analysed to explain the sequence of events required from both the a.c. and HVDC protection systems to clear the faults concerned.

Faults positioned between the onshore a.c. circuit breaker and d.c. converter within an HVDC Multi-terminal system may require additional protective actions to enable the fault to be cleared and requires further detailed investigation. This also applies to faults between the offshore d.c. converter and offshore a.c. circuit breaker respectively.

The speed of operation of the HVDC protection system is crucial to prevent the rate of rise of the d.c. fault current from being too excessive and exceeding the rating of the HVDC circuit breaker and other d.c. equipment [7]. Fast operation of the HVDC protection system is also required to prevent the collapse of the d.c. voltage for a d.c. side fault causing system instability. Hence further detailed investigations into these areas is also required.

The coordination between the a.c. protection and HVDC protection systems is fundamental to the correct detection and clearing of faults within an integrated offshore transmission network and also required further detailed analysis.

The ability of the d.c. converters to participate in the management of d.c. fault current depends on both the topologies employed, together with the earthing of the power system and will require additional examination, in addition to those currently already under study [9].

Study into wind farm protection system and coordination between this and the HVDC protection system also requires detailed analysis [8], [9].

7.4 References

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8. POWER FLOW CONTROL

8.1 Introduction

HVDC technology based on self-commutated voltage sourced converter has the capability of independent control of active and reactive power which makes integration of offshore wind farms and multi-terminal operation easier than for conventional a.c. and LCC HVDC. In this chapter, the functional requirements of primary and secondary control for VSC HVDC systems are introduced and the primary control methods and their characteristics are described. Application of power flow control is illustrated using a number of generic scenarios representing the basic types of connection that would be used in an integrated offshore transmission network. For each scenario, it is demonstrated how converter control characteristics can be coordinated to achieve the desired steady state power flows. It is also shown how a new operating point can be achieved following the loss of a transmission connection. An annex is included in which the characteristics of variable speed wind turbines relevant to their application in an integrated offshore transmission network are described.

8.2 Functional Requirements for Power Flow Control

8.2.1 Primary Control

The requirements for primary control in VSC-based d.c. systems have been summarised as follows [1]:

- Well-defined operating points that are easy to schedule
- Stable operating point after a large disturbance
- Possible to schedule for optimal power flow
- Possible to handle restrictions and limitations in both a.c. and d.c. networks
- Prevention of overload
- Voltage control
- Dynamic control division between several converter stations, to ease the influence on the a.c. system
- Automatic control, i.e. work without communication

Active and reactive power are controlled locally at a converter by means of pre-programmed control characteristics. In this way, the converter is able to respond to changing system conditions in the short term without dependence on communications.

8.2.2 Secondary Control

The functions of secondary control are described in [1] as follows:

- The secondary control actions in a d.c. grid comprise of a change in set points which dictate the overall steady state power flows in the grid, prevent overload of branches, minimize losses, re-establish regulator range and reschedule according to planned operation
- A central dispatch centre can use power flow tools to determine the desired grid state and use the results to alter the converter set-points in a slow manner through secondary control.
- The secondary control coordinates the power orders and d.c. voltage references to all stations in the d.c. grid.

The primary control characteristics of the converters in a d.c. system are coordinated so that the desired load flow is achieved and so that the overall response of the d.c. system to an event is acceptable and a new steady state operating condition is reached. Following such a change, new control parameters may be sent to the converter controllers by secondary control so that an optimised power flow is again achieved.

8.3 Primary Control Methods in VSC-HVDC

The most important feature of VSC-based systems is independent control of active and reactive power, *P* and *Q*, so that the four-quadrant operation capability can be achieved. The typical *P-Q* operating range for a VSC HVDC converter is shown in Figure 1[2].

The objectives for the power flow control in a VSC-based system, whether a point-to-point d.c. link or a multi-terminal d.c. grid, are to control the voltage and power through the converters and branches to meet the operation requirements of the a.c. and d.c. systems.

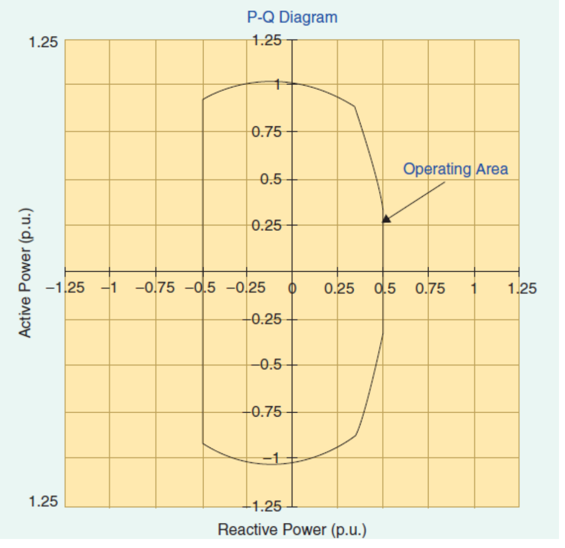

Figure 1: Typical P-Q Characteristics within a VSC-based Station [2]

8.3.1 Inner Current Controller of VSC

The vector control methods are widely applied in the controller design of the VSC-based systems to achieve the independent or so-called decoupled control of active and reactive power [3]. In Figure , the measured voltages and currents at the point of common coupling (PCC) in the three-phase *a-b-c* coordinate system are transformed into their own direct and quadrature *d*- and *q*-axis components in the rotational *d-q* coordinate system via the Park transformation [4]. The *d-q* coordinate system rotates in synchronism with the power frequency voltage and the phase angle is usually selected such that quantities related to active power are aligned with the *d*-axis and quantities related to reactive power with the *q*-axis.

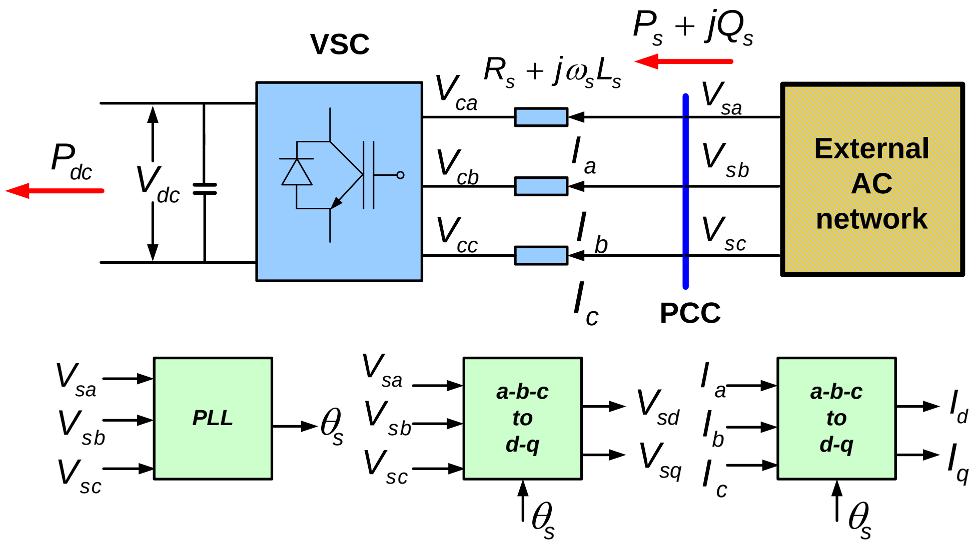

Figure 2: Park Transformation for a-b-c to d-q Coordinate System

A VSC controller is usually designed based on the cascaded two-stage controller structure. In the inner current controller shown in Figure , the *d*- and *q*-axis components I_d and I_q are compared with their own references and the errors are sent to the proportional integral (PI) regulators to provide the required modulation index (voltage) for generating the firing signals to turn on or off the VSC [4]. With this design structure of the inner current controller, the control of *d*- and *q*-axis currents can be decoupled [5].

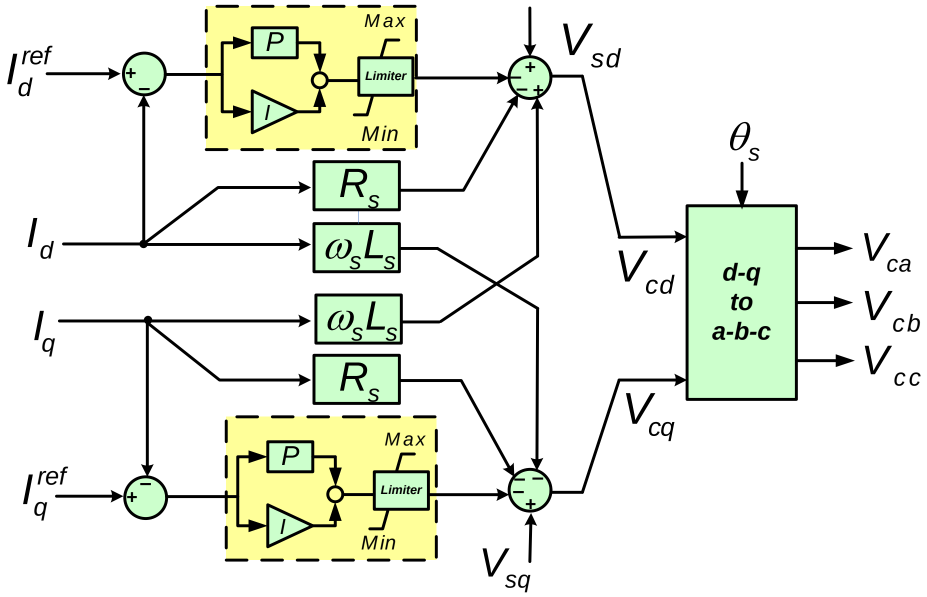

Figure 3: Control Schematic of Inner Current Controller

8.3.2 Outer Controller of VSC

For the outer controller, the measured variable is compared with its reference and their error is then sent to the PI regulator to provide the *d*- or *q*-axis current reference for inner-stage current controller mentioned above [3]. In different operation conditions, different control objectives e.g. constant active power or voltage can be achieved via the *d*- or *q*-axis outer controller to maintain the normal operation of VSC-based systems.

8.3.2.1 Power Controller

8.3.2.1.1 Constant Active Power Controller

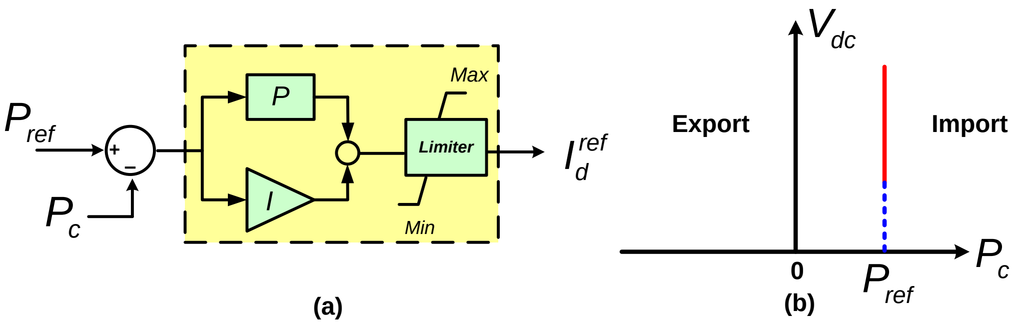

Figure 4: The Constant Active Power Controller

The control schematic of a constant active power controller is shown in Figure 4 (a) [3, 4]. The active power P_c measured at the a.c. terminal of the VSC is compared with the preset reference P_{ref}. The error is sent to the PI regulator to provide the *d*-axis current reference. In order to limit the magnitude of current to within the allowable range, the output of the active power is followed by a limiter function. At steady state, with the constant active power controller, P_c equals P_{ref}.

The characteristic of this controller represented by the "d.c. voltage vs active power" curve is illustrated in Figure 4 (b) [6]. P_{ref} is set regardless of the level of the d.c. voltage V_{dc}, hence the vertical line shows the characteristics of constant active power controller. For the purposes of this report, 'import' refers to the import of power to the HVDC system and 'export' refers the export of power from the HVDC system.

8.3.2.1.2 Constant Reactive Power Controller

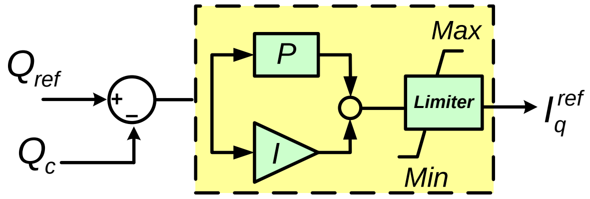

Figure 5: Control Schematic of Constant Reactive Power Controller

The control schematic of constant reactive power controller is shown in Figure 5 [3, 4]. The *q*-axis current reference can be obtained by regulating the error between the reactive power Q_c measured at the a.c. terminal of the VSC and the preset reference Q_{ref}, similar to the constant active power controller. At steady state, with this controller, Q_c equals Q_{ref}.

8.3.2.2 Voltage Controller

8.3.2.2.1 Constant DC Voltage Controller

By controlling the d.c. voltage to a constant value, the balance between active power imported onto the d.c. system and exported from the d.c. system is maintained. The control schematic of constant d.c. voltage controller is shown in Figure 6 (a) [3]. In a similar way to the constant active power controller, the *d*-axis current reference can be obtained by regulating the error between the measured d.c. voltage V_{dc} at the d.c.-side of the VSC and its preset reference V_{dc}^{ref}. At steady state, V_{dc} equals V_{dc}^{ref} and the characteristics of the constant d.c. voltage controller are as illustrated in Figure 6 (b) [6]. The d.c. voltage reference is set regardless of the level of active power, so that the horizontal line shows the characteristics for the d.c. voltage controller. Note that, should I_d reach one of its limits, it will no longer be possible to balance the power flows and the d.c. voltage will either fall (if the converter is importing power to the d.c. system) or rise (if the converter is exporting power from the d.c. system).

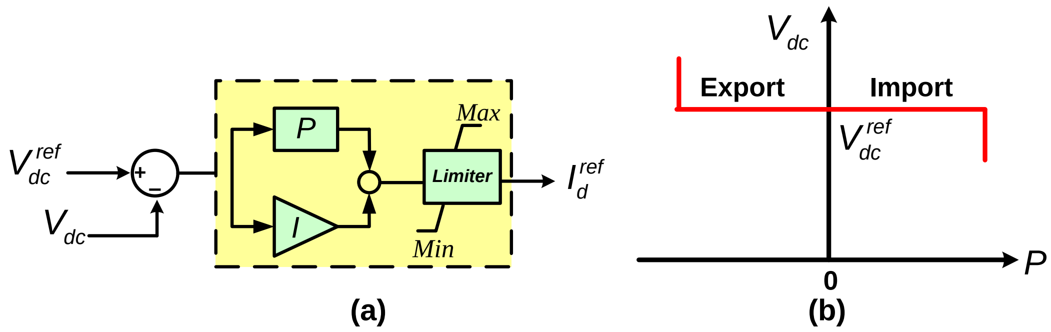

Figure 6: The Constant d.c. Voltage Controller

8.3.2.2.2 Constant AC Voltage Controller

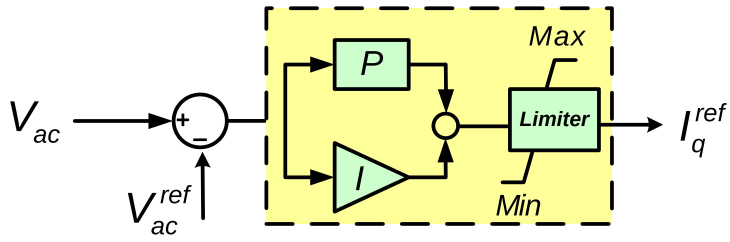

Figure 7: The a.c. Voltage Controller

The control schematic of a.c. voltage controller is shown in Figure 7[3]. In a similar way to the constant reactive power controller, the *q*-axis current reference can be obtained by regulating the error between the measured a.c. voltage V_{ac} at the a.c. terminal of a VSC and its preset reference V_{ac}^{ref}. At steady state, V_{ac} equals V_{ac}^{ref}.

8.3.2.3 DC Voltage Droop Controller

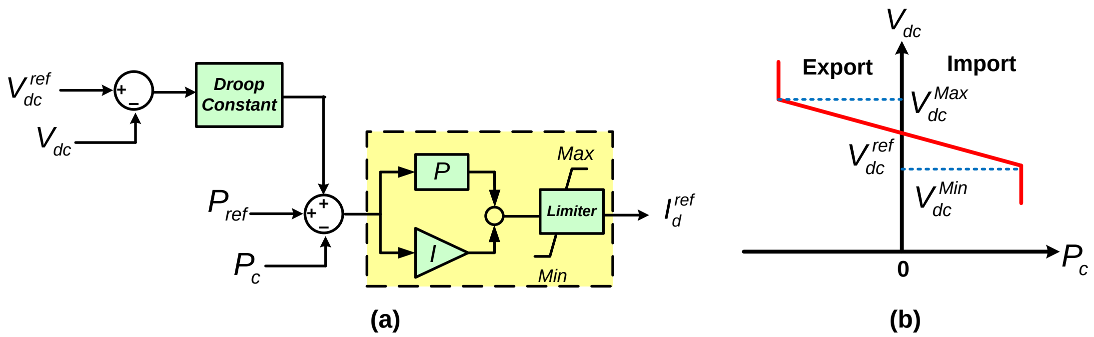

Figure 8: d.c. Voltage Droop Controller

The d.c. voltage droop controller uses the error between the measured d.c. voltage V_{dc} and the reference voltage V_{dc}^{ref} to generate an additional proportional offset in the power reference P_{ref} within the original active power controller. The principle is shown schematically in Figure 8 (a). The d.c. voltage droop controller characteristic is shown in Figure 8 (b) [1, 6]. The droop constant is defined as: $\frac{\Delta V_{dc}}{\Delta P_c} = K_{droop}$

Such control characteristics are usually applied in the MTDC systems to share the role of "slack bus" between several terminals instead of only one terminal [7].

8.3.2.4 Frequency Control

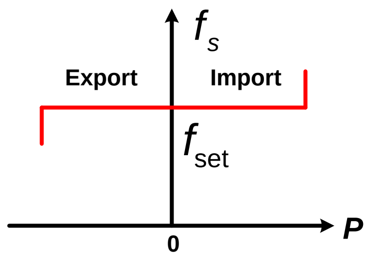

Figure 9: Constant Frequency Characteristic

The constant frequency controller usually works together with constant a.c. voltage controller in the VSC-based systems to provide the frequency and voltage references for weak a.c. systems e.g. islands and offshore wind farms [1, 2, 4]. The characteristics of the constant frequency controller are illustrated in Figure 9 [8]. The frequency reference is set regardless of the level of active power, so that the horizontal line shows the characteristics for constant frequency controller. Where limits are set, should I_d reach one of its limits, the frequency will either rise (if the converter is importing power to the d.c. system) or fall (if the converter is exporting power from the d.c. system).

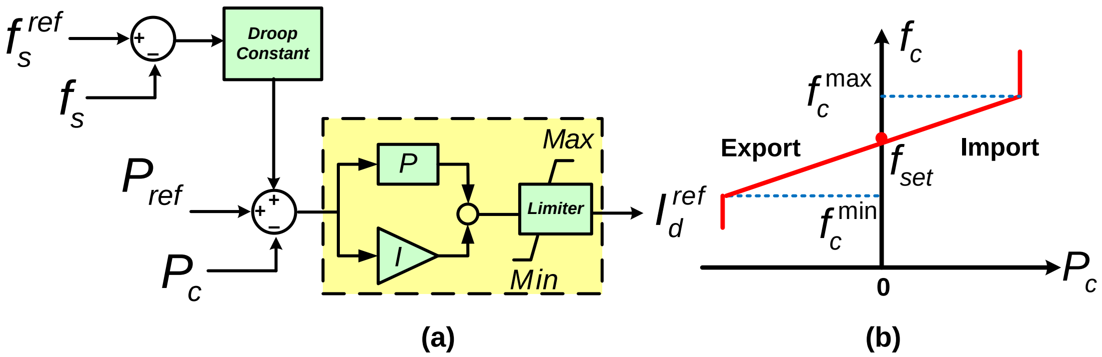

Figure 8: Frequency Droop Controller

With the frequency droop controller shown in Figure 10 (a), the functionality of frequency droop characteristics in a conventional synchronous generator can be achieved in the VSC-based systems [4, 6]. In a similar way to the d.c. voltage droop controller in Section 0, the error between the measured frequency f_s and the reference frequency f_s^{ref} is used to generate an additional proportional offset in the power reference P_{ref} within the original active power controller. The characteristics of the frequency droop controller are shown in Figure 10 (b) [4, 6, 8]. The droop constant is defined as:

$$\frac{\Delta f_c}{\Delta P_c} = K_{droop}$$

In order to optimise the network for the varied power dispatch, the master control adjusts the droop constants power and frequency references in the VSC-based system.

8.4 Variable Speed Wind Turbine Generators

The wind turbine generators connected to an integrated offshore transmission network are likely to be of the variable speed type. One of the key differences between MW-level variable-speed wind turbine generators and conventional generators is the use of back-to-back a.c./d.c./a.c. frequency converters. The frequency converters, typically IGBT-based voltage-sourced converters, are able to control their active and reactive power independently for four-quadrant operation [9, 10]. Consequently, these wind turbine generators can capture wind energy over a wide range of wind speed and their efficiency can be improved compared with fixed-speed wind turbine generators without frequency converters [11].

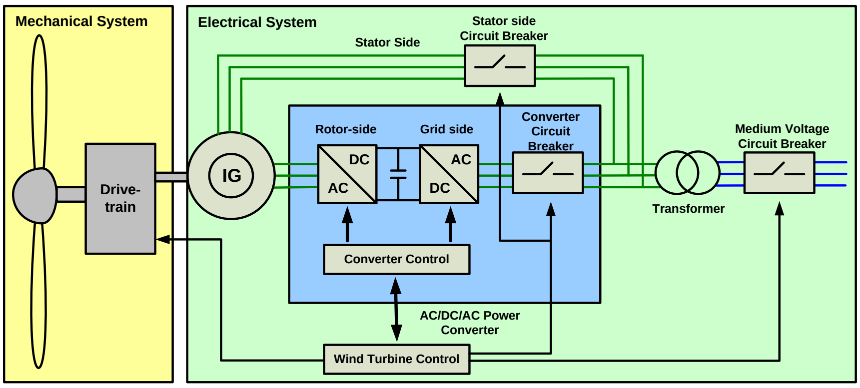

Figure 11: General schematic of DFIG

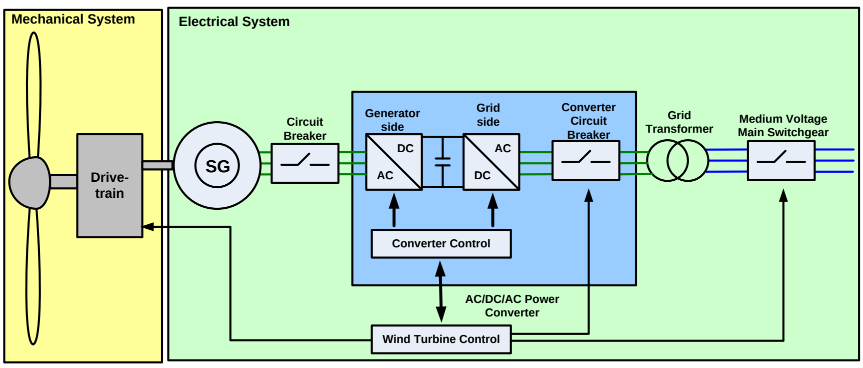

Figure 12: General schematic of FSC

Variable-speed WTGs are typically divided into two types according to the general configurations of their electrical system [9 - 12]:

1) Wind turbine with doubly-fed induction generator (DFIG)

2) Wind turbine with full-scale frequency converter (FSC)

The electrical system of a DFIG is shown in Figure 11 [10]. The stator of an induction generator is connected directly to the external grid. However, a frequency converter is inserted between the rotor of the induction generator and the external grid. With this layout, a portion of power from the generator's rotor (typically 25-30% of generator capacity) can be controlled by the frequency converter and the DFIG can operate over the variable-speed range of ±30% around the synchronous speed [12].

The electrical system of a FSC is shown in Figure 12 [10]. The frequency converter is connected in series with the stator of the synchronous generator so that the generator's power can be fully controlled by the frequency converter to perform smooth grid connection over the entire speed range [12]. However, for the same generator capacity, the power rating of the frequency converter in a FSC will be larger than that of a DFIG and the power losses and equipment costs will be higher.

The characteristics of variable speed wind turbine generators relevant to their connection to an integrated offshore transmission network are described in the annex to this chapter.

8.5 Application of Load Flow Control in Generic Scenarios

In this section, the application of load flow control is illustrated using a number of generic scenarios representing the basic types of connection which would be used in an integrated offshore transmission system. In each case, converter control strategies are chosen such that the desired steady state load flow is achieved. The response to the loss of a connection, such as might be caused by a fault or a converter trip, is considered for each possible case and the subsequent achievement of new operating points demonstrated.

8.5.1 Scenario 1: Point-to-Point VSC-HVDC Link

In Scenario 1, an offshore wind farm *WF* is connected to the onshore a.c. network via a point-to-point VSC-HVDC link L_1 as illustrated in Figure 13. The HVDC link has converters located onshore at T1 and offshore at T2. The frequencies of the onshore and offshore a.c. networks are f_{on} and f_{off}, respectively. The power imported by the offshore converter at T2 is P_{ofc}.

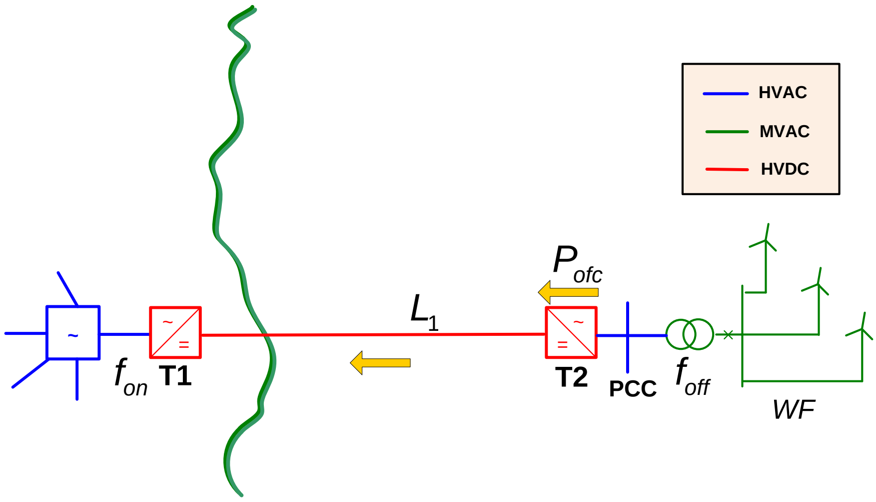

Figure 13: Point-to-Point HVDC Link

8.5.1.1 Control Strategies for Converters

The offshore wind farm is a weak a.c. network which is not easily able to provide the voltage and frequency references by itself. In this way, the offshore converter T2 needs to play the role as the reference machine for setting references of frequency and voltage at the point of common coupling (PCC) of the offshore a.c. network. The offshore converter at T2 maintains the frequency of the offshore a.c. network at a constant value so that the power imported into the d.c. link is maintained in balance with the power generated by the offshore wind farm. The onshore converter at T1, maintains a constant d.c. voltage on the d.c. link so that the power exported from the d.c. link to the onshore a.c. network is maintained in balance with the power imported to the d.c. link from the wind farm. The control strategies for the two terminals are summarised in Table 1.

Table 1: Control Strategies Proposed for Converters in Scenario 1

	Active Power	Reactive Power
T1	Constant V_{dc}	Constant Q
T2	Constant f	Constant V_{ac}

8.5.1.2 Loss of Connection

In the event that the HVDC link L_1 is tripped, all power transmission from the offshore wind farm to the onshore a.c. network will be lost. Consequently, the volume of generation connected by such a d.c. link may not exceed the limits on loss of infeed permitted by planning standards [13, 14].

Following loss of the d.c. link, the power generated by the wind turbines will cause the turbines' rotational speed to accelerate. Curtailment of the generated power is required to prevent over-speed of the turbines, rotor overcurrent in the generators and overvoltage/overcurrent in the d.c. link of the generators' frequency converters, particularly under high wind generation conditions. The protection strategies proposed to manage such risks are discussed in the annex to this chapter.

Grid codes typically require a fault ride through capability for the offshore wind turbines in the event of faults on the onshore a.c. network [15, 16]. For the VSC-HVDC link, a thyristor-switched resistor bank at the onshore end of the d.c. system may be used for isolating the offshore wind farm from a.c. faults on the onshore a.c. network [9]. This solution has been used in the BorWin 1 project.

8.5.2 Scenario 2: Offshore AC connection

In Scenario 2, two offshore wind farms, WF_1 and WF_2, are each connected to the onshore a.c. network by point-to-point HVDC links L_1 and L_2. The wind farms are connected on the a.c. side by a connection L_3. The arrangement is shown in Figure 14.

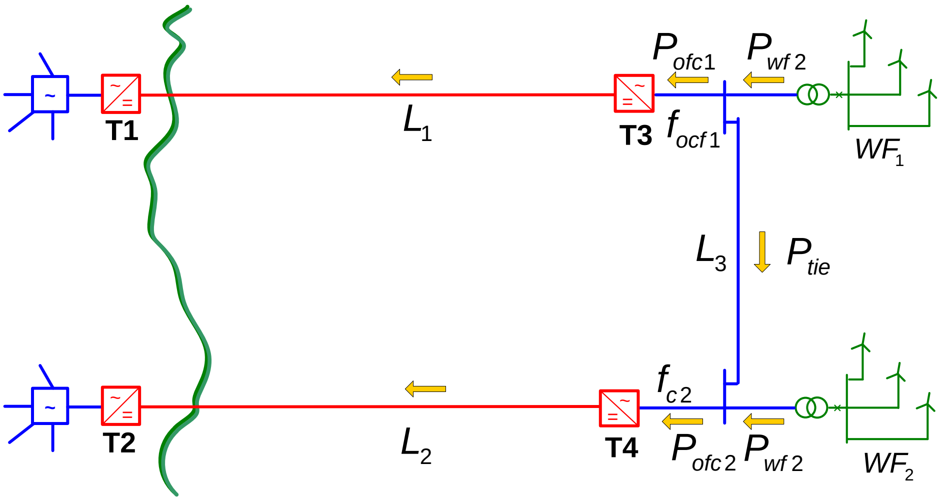

Figure 14: Offshore a.c. Interconnector for Two Parallel HVDC Links

In this arrangement, spare capacity on the HVDC links can be used for cross boundary power transfer for the onshore a.c. network when the wind generation is less than maximum. Referring to Figure 14, the power generated by WF_1 is P_{WF1} and the power imported by the offshore converter at T3 is P_{ofc1}. The power generated by WF_2 is P_{WF2} and the power imported by the offshore converter at T4 is P_{ofc2}. The direction of the power flow P_{tie} through the a.c. connection is from WF_1 to WF_2. The power flow of two offshore a.c. converters can be represented:

$$\begin{cases} P_{ofc1} = P_{WF1} - P_{tie} \\ P_{ofc2} = P_{WF2} + P_{tie} \end{cases}$$

8.5.2.1 Control Strategies for Converters

A similar scenario to Scenario 2 was studied in [17]. Constant d.c. voltage control and constant *Q* control were proposed for both of the onshore converters (corresponding to T1 and T2 in Scenario 2), while frequency droop control and constant a.c. voltage control is proposed for the offshore converters (corresponding to T3 and T4). A similar scenario to Scenario 2 was studied in [8], except that the offshore a.c. network was connected to the onshore network by three HVDC links. Applying the principles used in [8], a further two strategies for the present scenario may be proposed. The three proposed strategies are summarised in Table 2.

Table 2: Possible Control Strategies for Converters in Scenario 2

	T3	T4
Strategy 1	*f* Droop	*f* Droop
Strategy 2	Constant *f*	*f* Droop
Strategy 3	Constant *f*	Constant *P*

In [8], there are two key conclusions with regard to the control strategies:

- For Strategy 1, the use of frequency droop control allows load sharing between the HVDC links to be achieved. However, unexpected large load unbalances can occur under some conditions.
- For Strategy 2 and 3, the frequency will be constant. Load sharing can be achieved by smart power dispatch. However, Strategies 2 and 3 impose high requirements on communication between the central control and the individual converter controls.

Due to the fast response required of the d.c. system, it is not recommended to rely on communication for primary control of the power flow at disturbances [1]. As a result, the Strategy 1 may be more practical than Strategy 2 and 3 in terms of requirements for automatic control.

Based on [8, 17], the control strategies for converters T1 to T4 are proposed in Table 3.

Table 3: Proposed Control Strategies for Converters in Scenario 2

	Active Power	Reactive Power
T1	Constant V_{dc}	Constant Q
T2	Constant V_{dc}	Constant Q
T3	f Droop	Constant V_{ac}
T4	f Droop	Constant V_{ac}

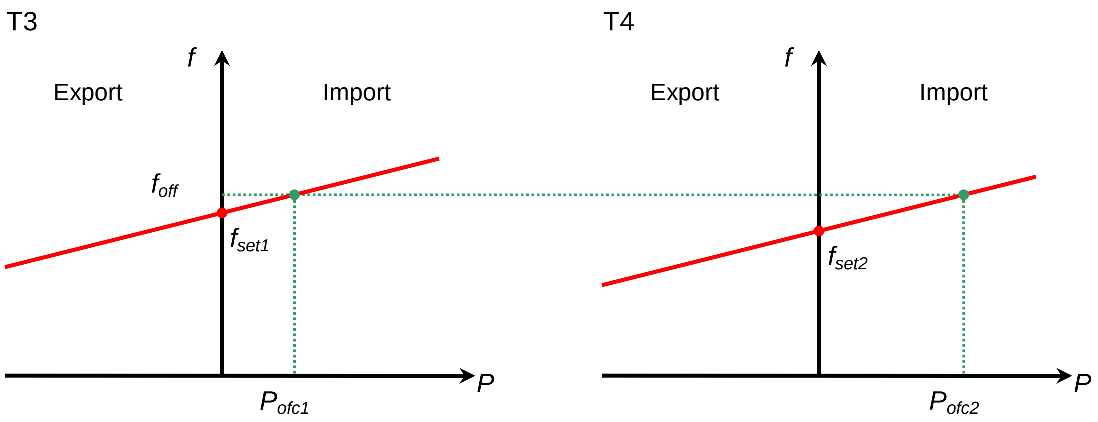

Figure 15: Power Dispatch between T3 and T4

The use of frequency droop control to achieve sharing of power between terminals T3 and T4 is illustrated in Figure 15. The two offshore a.c. networks are coupled via the HVAC interconnector and share a common frequency f_{off}. The power import at each converter is determined by its control characteristic. The power share can be changed by shifting the control characteristic of either converter up or down the frequency axis.

8.5.2.2 Loss of Connection

a) Loss of HVDC Link L_1

In the event that the HVDC link L_1 is tripped, the frequency of the offshore a.c. network comprising WF_1 and WF_2 will increase and the converter at T4 will adjust its operating point to increase its power import in accordance with its frequency droop characteristic. This is represented by the move from Operating Point 1 to Operating Point 2 in Figure 16. If the total power generation of the two wind farms is within the capacity of the converter at T4, a new, stable operating point will be reached. New reference points will subsequently be sent to the controller of T4, as represented by the move from Operating Point 2 to Operating Point 3 in Figure 16 as the frequency is restored.

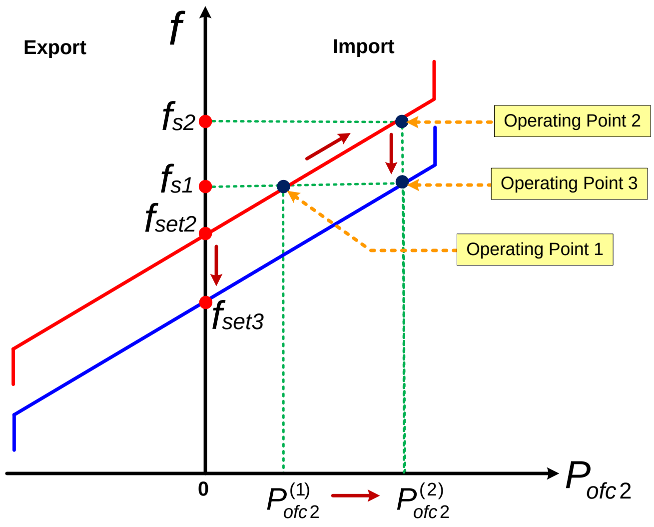

Figure 16: Change in Operating Points for Converter at T4

If the total power generation of the two wind farms exceeds the capacity of the converter at T4, urgent action will be required to manage the excess power. The IGBTs in the valves of a VSC HVDC converter cannot support overload conditions for more than a few milliseconds. In the event of an overload, the converter at T4 will rapidly be tripped with the loss of all connected generation. It is possible to prevent the converter at T4 from overload by using its control system to limit the current, but some means must still be found to manage the excess generated power.

In principle, it would be possible to reduce power generation by control action, possibly using the frequency of the offshore network as a trigger. A power reduction controller has been proposed in [17]. It was stated that due to the fast response of the wind turbine converters, the output power is reduced quickly.

Strategies to manage excess power generation in a similar scenario to the present one have also been described in [8]. The scenario considered connection of an offshore a.c. network to the onshore network by multiple HVDC links, where the loss of one might result in overload of the remaining links and cascade tripping of all of them.

- A partial solution is to design the system such that the total generated power can be accommodated with the loss of the largest link.

- A semi-conductor controlled resistor bank (or ‘chopper’) connected to the offshore a.c. side would be a feasible solution, but would require significant additional investment in primary plant and platform infrastructure.

- Tripping excess generation might be a solution provided the level of overload on the remaining converters is sufficiently low that they can withstand the time required for decision plus circuit-breaker operation before tripping. In order to ensure that the level of overload be sufficiently low, the total generation connected under normal conditions would have to be restricted.

In [8], the longer time constant for reduction of power from the wind turbine generators was contrasted against the short overload time limits of VSC HVDC converters. Changing the turbine blade pitch angles may provide a reduction of around 25% of nominal power per second. The implication is that, by itself, power reduction by blade pitch control is too slow to be a solution.

Once the excess generation has been managed, new reference points will be sent to the controller of T4 to optimise the power flow under the new conditions.

The risk of the converter at T4 overloading and tripping following a trip of HVDC link L_1 could be eliminated by operating with the offshore a.c. connection L_3 normally open. The system would operate as two independent point-to-point HVDC links as described in Section 5.1. Thus, in the event that HVDC link L_1 tripped, power transmission from WF_1 to the onshore a.c. system would be lost but transmission from WF_2 would be unaffected. Should L_1 be out of service for a sufficient length of time, the offshore a.c. connection L_3 would be closed to allow generation from WF_1 to make use of any spare transmission capacity existing on HVDC link L_2. This arrangement would increase the availability for WF_1 compared with the point-to-point connection of Section 5.1, but would not contribute to cross boundary power transfer for the onshore a.c. network.

b) Loss of HVDC Link L_2

In the event that the HVDC link L_2 is tripped, the frequency of the offshore network will rise and the converter at T3 will attempt to adjust its operating point until all power generated by the two wind farms is transmitted by the remaining link L_1. Should the total power generation of the two wind farms exceed the capacity of the converter at T3, urgent action will be required to prevent overload and tripping as described above for the loss of L_1. The considerations related to managing excess generation are similar. Finally, new reference points will be sent to the controller of T3 to optimise the power flow under the new conditions.

The risk of the converter at T3 overloading and tripping following a trip of HVDC link L_2 could be eliminated by operating with the offshore a.c. connection L_3 normally open, as described above for the loss of L_1. This arrangement would increase the availability for WF_2 compared with the point-to-point connection of Section 5.1, but would not contribute to cross boundary power transfer for the onshore a.c. network.

c) Loss of offshore a.c. connection L_3

Where offshore wind farms are connected by means of an offshore a.c. connection, as represented by L_3 in Figure 14, it becomes increasingly important that the generators be able to remain transiently stable and connected for the fault clearance time in the event of a short circuit fault on the offshore a.c. network. Given the exclusive use of wind turbine generators and cable connections, the fault ride through requirements of existing grid codes may not be sufficiently onerous for the offshore a.c. network.

In the event that the offshore a.c. connection L_3 is tripped, and assuming that all generation has remained connected, the offshore frequencies at terminals T3 and T4 will be decoupled and, clearly, the power flow P_{tie} through the a.c. connection will equal zero.

In the milliseconds following the loss, the frequency of T3 moves up with its droop controller as the power previously transmitted by the a.c. connection flows into T3. T3 will increase its import of power to the HVDC link according to its *f* vs *P* droop characteristic shown in Figure 17(a). Meanwhile, the frequency of T4 moves down with its droop controller as the power previously imported from the a.c. connection is no longer imported by T4. T4 will reduce its power import according to its *f* vs *P* droop characteristic shown in Figure 18(a).

There is no risk of overload for T3 and T4 and the whole system will survive and enter new operating conditions. After surviving the emergency state, the original system becomes two independent point-to-point HVDC links as described in Section 0. The central dispatch may change the controllers of T3 and T4 from frequency droop control to constant frequency control with new reference points as shown in Figure 17(b) and Figure 18(b).

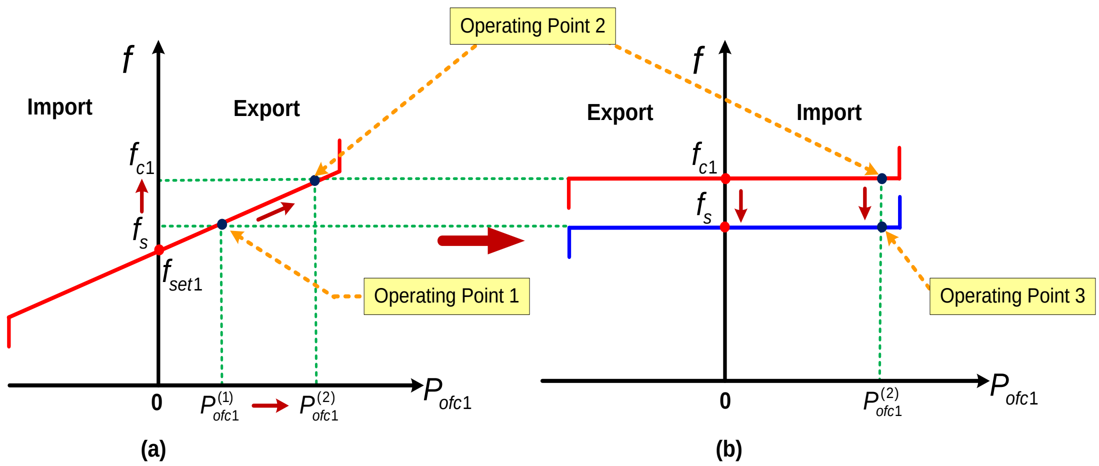

Figure 17: New Reference Point for T3 after System Restoration

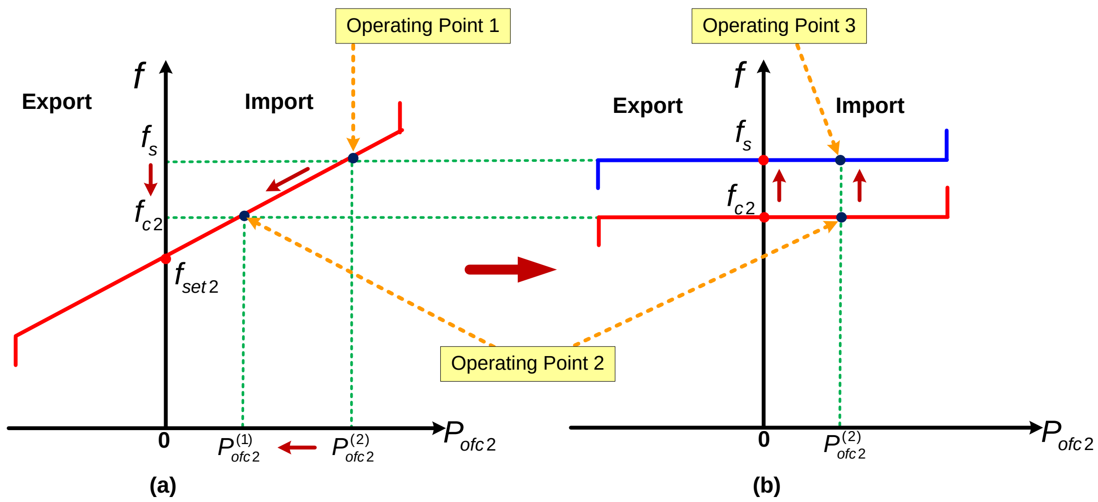

Figure 18: New Reference Point for T4 after System Restoration

8.5.3 Scenario 3: Offshore point-to-point HVDC connection

In Scenario 3, two offshore wind farms, WF_1 and WF_2, are each connected to the onshore a.c. network by point-to-point HVDC links L_1 and L_2. The wind farms are connected on the a.c. side by a point-to-point HVDC link L_3. The arrangement is shown in Figure 19.

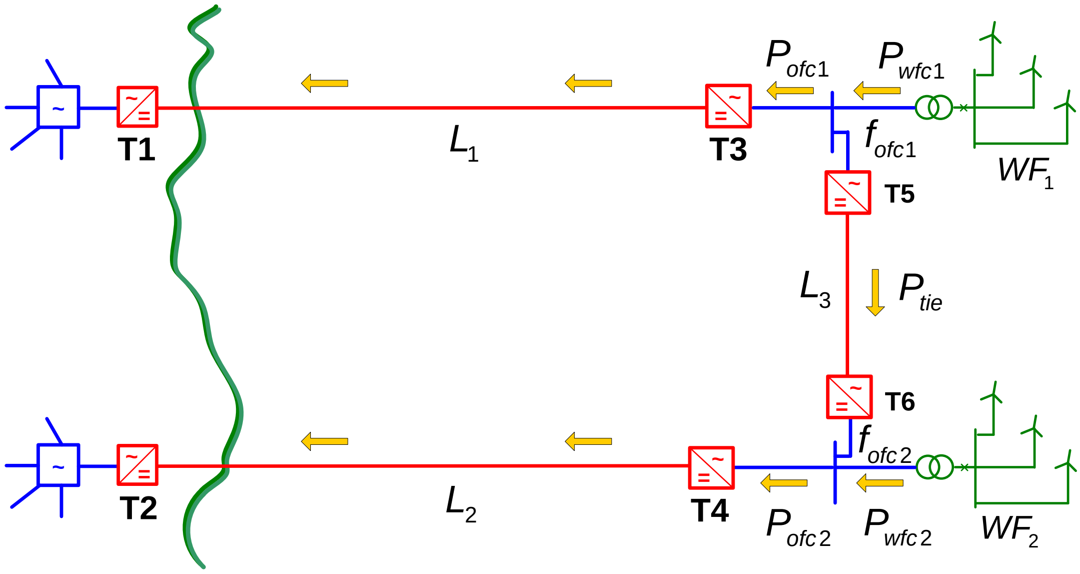

Figure 19: Offshore point-to-point HVDC connection for two parallel VSC-HVDC links

In this arrangement, the frequencies f_{ofc1} and f_{ofc2} of the two offshore a.c. networks are independent. It is assumed that the power rating of the converters at T5 and T6 is equal to that of the other converters. As in the case of Scenario 2, this arrangement allows spare capacity on the HVDC links to be used for cross boundary power transfer when the wind generation is less than maximum.

8.5.3.1 Control Strategies for Converters

For the converters at T1 and T2, the constant d.c. voltage controller and constant reactive power controller are used. For the converters at T3 and T4, the frequency droop controller is used. The converters at T3 and T5 share a common frequency, so the frequency droop controller is also proposed for T5. Since at least one converter of a HVDC link must participate in d.c. voltage control, the constant d.c. voltage controller is used for T6. For reactive power control, the constant reactive power controller is used for T5 and T6. The proposed control strategies are summarised in Table 4.

Table 4: Proposed Control Strategies for Converters in Scenario 3

	Active power	Reactive power
T1	Constant V_{dc}	Constant Q
T2	Constant V_{dc}	Constant Q
T3	f Droop	Constant V_{ac}
T4	f Droop	Constant V_{ac}
T5	f Droop	Constant Q
T6	Constant V_{dc}	Constant Q

8.5.3.2 Loss of Connection

a) Loss of d.c. Link L_1

In the event that the HVDC link L_1 is tripped, the frequency of the wind farm *WF1* will change and T5 will adjust its operating point until the power previously transmitted through L_1 is transmitted through L_3. In turn, the frequency of the wind farm *WF2* will change due to the change in power transmitted through L_3 and the converter at T4 will change its operating point to import the total generation of the two wind farms.

If the total power generation of the two wind farms is within the capacity of the converter at T4, a new, stable operating point will be reached. Should the total power generated by the wind farms exceed the rating of T4, action will need to be taken to manage the excess power as in the previous scenario.

Finally, the central dispatch will send new reference points to the controllers of the remaining converters to optimise load flow under the new conditions.

b) Loss of d.c. Link L_2

The loss of L_2 in this scenario would present a greater challenge. In the event of L_2 being tripped, wind farm WF_2 would lose its frequency reference. Furthermore, T6 is in d.c. voltage control mode and would not adjust its operating point in response to the loss of L_2. It might be possible to change the control mode of T6 to frequency or frequency droop control and that of T5 to d.c. voltage control, but it is not clear whether this could be achieved sufficiently quickly. It would also impose a dependence on telecommunications which might be better avoided. Possible solutions require further investigation.

An alternative strategy would be to avoid the use of a converter in d.c. voltage control mode at the wind farm end of a connection. In the present scenario, if L_1 and L_3 were combined to form a multi-terminal HVDC link connecting T1, T3 and T6, then T6 could be in frequency droop control mode. In the event that L_2 was tripped, T6 would adjust its operating point until all power generated by the wind farm WF_2 is transmitted through L_3.

Finally, new reference points will be sent to the converter controllers to optimise the load flow under the new conditions.

c) Loss of offshore d.c. connection L_3

In the event of the offshore HVDC link L_3 being tripped, the frequencies of the offshore networks would change and the operating points of T3 and T4 would adjust as the power generated by *WF1* is transmitted by L_1 and the power generated by *WF2* transmitted by L_2. The system would operate as two separate point-to-point HVDC links as described in 4.1.

Following the disturbance, new reference points will be sent to the controllers of the converters at T3 and T4.

8.5.4 Scenario 4: Offshore Multi-terminal HVDC Grid

In Scenario 4, two offshore wind farms WF_1 and WF_2 are connected to the onshore network by a multi-terminal DC grid as shown in Figure 20**.**

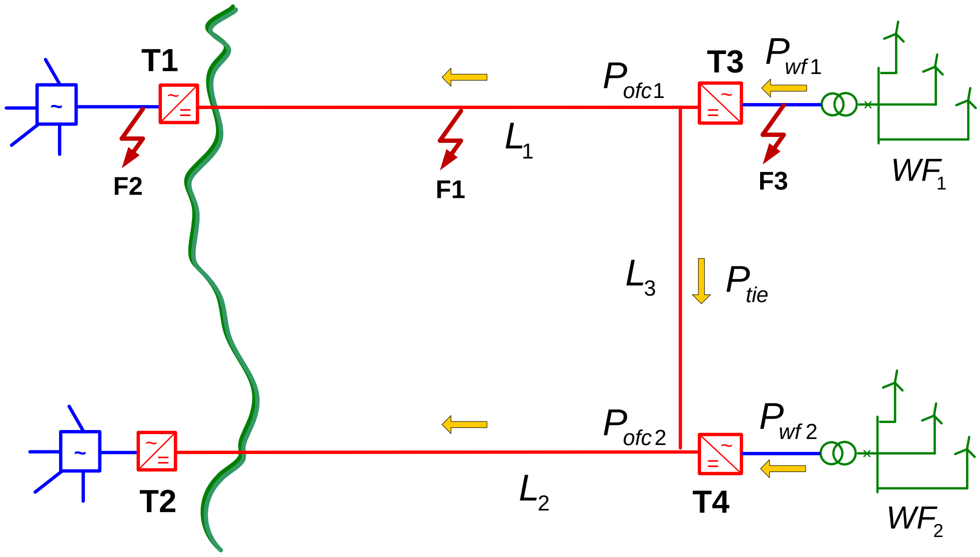

Figure 20: Multi-Terminal d.c. Grid for Integration of Two Offshore Wind Farms

8.5.4.1 Control Strategies

The onshore converters T1 and T2 share the role of maintaining the d.c. voltage in the HVDC system using their d.c. voltage droop controllers [4, 7]. The frequency droop controller is used for the converters at T3 and T4. The proposed control strategies are summarised in Table 5.

Table 5: Proposed Control Strategies for Converters in Scenario 4

	Active Power	Reactive Power
T1	V_{dc} Droop	Constant Q
T2	V_{dc} Droop	Constant Q
T3	f Droop	Constant V_{ac}
T4	f Droop	Constant V_{ac}

8.5.4.2 Loss of converter

If any single converter on the multi-terminal HVDC system was tripped, a new stable operating point could be reached. If T1 was tripped, T2 would take sole control of the d.c. voltage. The d.c. voltage would rise or fall (depending on whether T1 was exporting or importing immediately before the trip) and the operating point of T2 would change as all power imported at T3 and T4 is transmitted through T2. If the total power generation of the two wind farms is within the capacity of the converter at T2, a new, stable operating point will be reached.

Should the total power generation exceed the capacity of T2, the excess generation would need to be managed. In contrast to the previous scenarios, the frequency of the wind farms *WF1* and *WF2* would not change. It is likely, however, that current limits would be implemented in the control system of the converter at T2 as shown in Figure 8. Consequently, when the power export limit for T2 is reached, the d.c. voltage of the HVDC system will rise. In [17], such a rise in d.c. voltage was used to trigger a transient frequency adjustment which in turn triggered the power reduction control of the wind turbine generators. The excess power generation will need to be reduced sufficiently quickly to prevent the d.c. system from tripping due to d.c. overvoltage.

The situation where T2 trips would be similar to the above, with T1 taking sole control of the d.c. voltage and exporting the total generated power.

If T3 or T4 was tripped, the d.c. voltage would fall and the sharing of power through T1 and T2 would be adjusted in accordance with their droop characteristics. There would be no risk of overload.

Following the disturbance, new reference points will be sent to the controllers of the remaining converters to optimise the load flow under the new conditions.

8.5.4.3 Loss of HVDC link (fault clearance with AC circuit-breakers)

Currently, there is no commercial application of an HVDC circuit-breaker in the protection of VSC-based systems [1]. In the absence of an HVDC circuit-breaker, a fault on the d.c. side of the multi-terminal HVDC system would be cleared by tripping the a.c. circuit-breakers of all converters. All generation infeed would be lost. Consequently, the total generation connected to the system may not exceed the limits on loss of infeed permitted by planning standards.

8.5.4.4 Loss of HVDC link (fault clearance with HVDC circuit-breakers)

If the branches L_1, L_2 and L_3 were protected using HVDC circuit-breakers, the unaffected branches of the multi-terminal system could continue operation in the event of a d.c. fault. If L_1 was tripped, the converter at T2 would take sole control of the d.c. voltage. The d.c. voltage would rise or fall, depending on whether L_1 was exporting or importing power prior to the trip, and the operating point of the converter at T4 would adjust to export all generated power from the wind farms WF_1 and WF_2. Should the total power generation exceed the capacity of the converter at T2, the excess power would need to be managed as discussed previously. The situation where L_2 trips would be similar, with the converter at T1 taking sole control of the d.c. voltage and exporting all generated power.

If L_3 was tripped, the converter at T1 would take control of the d.c. voltage of L_1 and adjust its operating point to export the power imported at T3. The converter at T2 would take control of the d.c. voltage of L_2 and adjust its operating point to export the power imported at T4.

Following any HVDC circuit-breaker trip, new reference points will be sent to the converter controllers to optimise the load flow under the new conditions.

8.6 Conclusions

The primary control methods and characteristics for VSC HVDC converters have been introduced and their application for power flow control in VSC-based HVDC systems has been described. Primary control strategies have been illustrated using a set of four generic scenarios, which represent the different basic types of connection that might be used in an integrated offshore transmission network.

In general, it is possible to propose control characteristics such that the desired load flow is achieved and an acceptable steady state operating point is reached following a major disturbance such as a fault or converter trip. However, challenges may arise where a converter connected to an offshore a.c. network is in d.c. voltage control mode, since it will not automatically adjust its operating point in response to changes in the offshore a.c. network. It remains to be established whether a rapid change in converter control mode is feasible.

Where offshore wind farms are connected by means of an a.c. connection, it becomes increasingly important that the generators be able to remain transiently stable and connected in the event of a short circuit fault in the offshore a.c. network, particularly where the combined generation volume exceeds the limits on loss of infeed permitted by planning standards. Due to the use of wind turbine generators and cable connections, it is possible that the fault ride through requirements of existing grid codes are not sufficiently onerous for application to an offshore a.c. network. The range of conditions in the a.c. offshore network that might occur in the event of a short circuit fault requires to be established and, if necessary, appropriate fault ride through requirements developed.

In an integrated system, when a connection to the offshore a.c. network is lost and the total generated power exceeds the capacity of the remaining connections, the excess power must be managed in order to prevent overload and cascade tripping of the remaining connections. Where connection is made by VSC HVDC links, rapid action is essential since the converters cannot support overload conditions for more than a few ms.

A number of methods for managing the excess power generation have been proposed. These range from power reduction by control action to the provision of semi-conductor controlled resistor banks (or ‘AC choppers’). Design of the system such that the total generation can still be accommodated with the loss of the largest connection would provide a partial solution. Tripping of generation might be a solution provided that the overload is sufficiently low that the converters can support the overload conditions for the time taken to trip the generation.

Reduction of power generation by changing the blade pitch angle of the wind turbine generators is relatively slow and is, in itself, unlikely to provide a solution. It may, however, be used to reduce the duty on alternative methods of managing excess power generation.

The scenarios discussed in this chapter have been concerned with steady state power flows. It will be necessary to perform studies to investigate the dynamic response of the a.c. and d.c. systems for the events studied in each scenario.

Studies are required to establish the effectiveness and the cost associated with each of the proposed solutions for managing excess power generation, including costs associated with restricting or tripping generation. It would be also worth exploring additional solutions. The potential of using synthetic inertia control to reduce the rate of change of frequency of the offshore a.c. network and thereby increase the time available to reduce power generation merits investigation. The development of new converter topologies with greater overload capability would alleviate the problem.

8.7 References

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Appendix A: Offshore wind farm characteristics

A.1. Variable-speed wind turbine generators

One of the key differences between MW-level variable-speed wind turbine generators and conventional generators is the introduction of back-to-back AC/DC/AC frequency converters. The frequency converters, typically IGBT-based self-commutated voltage-sourced converters, are able to control their active and reactive power independently for four-quadrant operation [1, 2]. Consequently, these wind turbine generators can capture wind energy over a wide range of wind speed and their efficiency can be improved compared with fixed-speed wind turbine generators without frequency converters [3].

Variable-speed wind turbine generators are typically divided into two types according to the general configurations of their electrical system [1-4]:

3) Wind turbine with doubly-fed induction generator (DFIG)

4) Wind turbine with full-scale frequency converter (FSC)

The electrical system of a DFIG is shown in Figure A1 [1]. The stator of an induction generator is connected directly to the external grid. However, a frequency converter is connected between the rotor of the induction generator and the external grid. With this layout, a portion of power from the generator's rotor (typically 25-30% of generator capacity) can be controlled by the frequency converter and the DFIG can operate over the variable-speed range of ±30% around the synchronous speed [3].

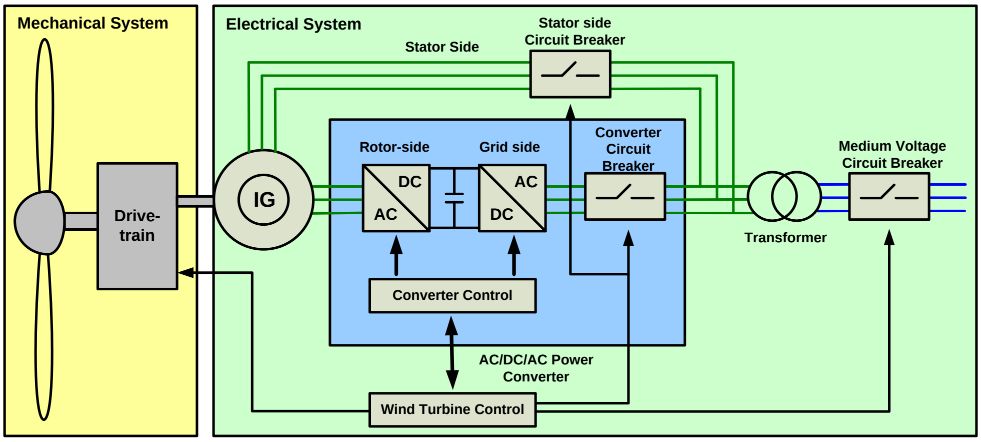

Figure A1: General schematic of DFIG

The electrical system of a WT-FSC is shown in Figure A2 [1]. The frequency converter is connected in series with the stator of the synchronous generator so that the generator's power can be fully controlled by the frequency converter to perform smooth grid connection over the entire speed range [3]. However, for the same generator capacity, the power rating of the frequency converter in a FSC will be larger than that of a DFIG and the power losses and equipment costs will be higher.

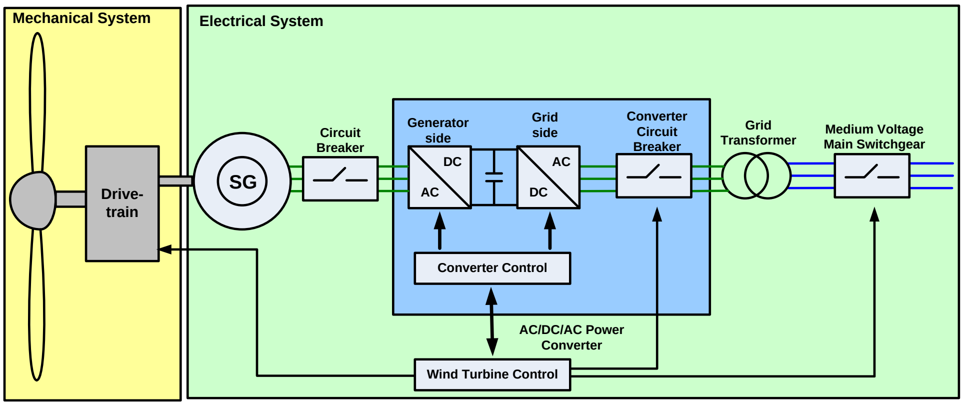

Figure A2: General schematic of WT-FSC

A.2. Primary frequency response

With the introduction of the frequency converters, the rotational speed of the WTG is decoupled from the system frequency. Consequently, the wind turbine generators in an offshore wind farm offer little or no natural response, unlike conventional generators. As a result, the increasing integration of these wind farms will lead to continuous reduction of system inertia which may bring issues of rate of change of frequency (ROCOF) when a severe generator-demand power imbalance occurs.

A.2.1. Primary frequency response requirements

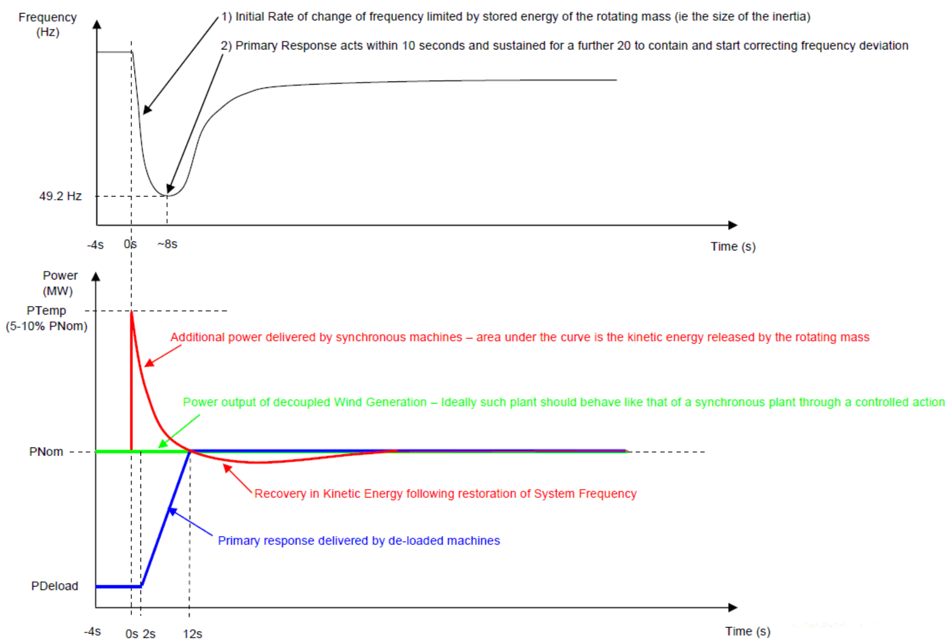

Figure A3: Primary frequency response requirements proposed by National Grid [5]

The impacts of ROCOF due to low-inertia wind farms lead to continuous demands for primary frequency response. For National Grid, an investigation into primary frequency response proposed that a power increase of 5-10% during an event where grid frequency drops to 49.2 Hz in approximately 8 seconds would be sufficient for the GB transmission system. The system frequency and the power increase during such an event are illustrated in A3 [5]. In order to meet these requirements, different methods have been proposed with the aim of releasing the stored or reserve energy of the variable-speed wind turbine generators to provide ancillary services similar to conventional generators for primary frequency response support to onshore a.c. networks using the strategies shown in Figure A4.

A.2.2. Solutions

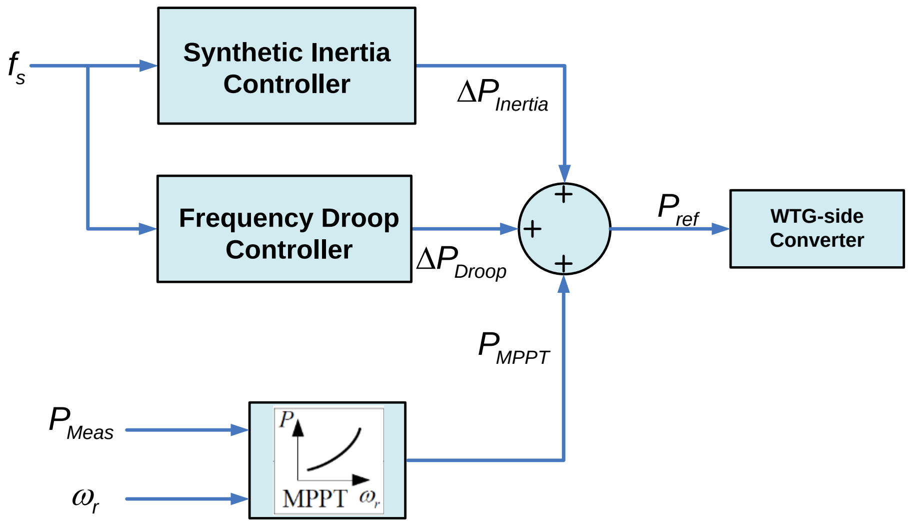

Figure A4: Strategies for primary frequency response enhancements for variable-speed wind turbine generators

A.2.2.1. Synthetic inertia

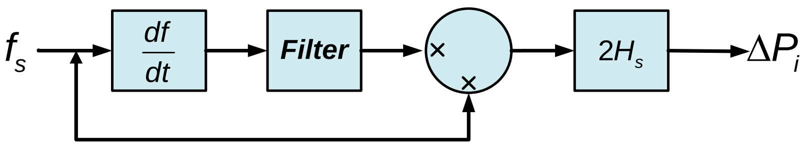

Figure A5: Synthetic inertia controller

Synthetic inertia controllers, as illustrated in Figure A5 [6], are being developed by some manufacturers to enable a variable-speed wind turbine generator to provide synthetic inertia response similar to the response of conventional generators by releasing a large amount of kinetic energy stored in its rotating mass [6-8]. The synthetic inertia response can last for several minutes, following which the wind turbine generator's rotor needs to be accelerated by absorbing power from the grid.

A.2.2.2. Frequency droop control

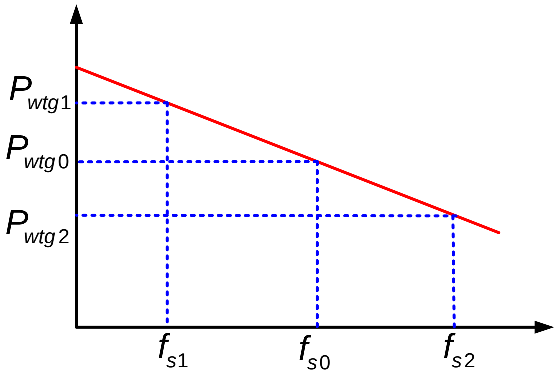

Figure A6: Frequency droop controller

Moreover, more and more wind turbine generators have been or will be upgraded with frequency droop control similar to conventional generators with a power-frequency characteristic as shown in Figure A6 [9]. The capability of frequency droop control is heavily dependent on the selected droop gain value *Kdroop* where:

$$K_{droop} = -\frac{\Delta P_{WTG}}{\Delta f_s}$$

By virtue of the capabilities of frequency droop control with a suitable K_{droop} and synthetic inertia response, the frequency performance in low-inertia systems may be significantly improved.

A.3. Fault ride through

In order to ensure system stability, grid codes usually require generation to be able to remain connected when the system voltage is reduced due to a fault [10, 11]. The protection and control schemes of the frequency converters need to be configured to meet the requirements of fault ride through (or low voltage ride-through) specified in grid codes.

A.3.1. Solutions

For a DFIG [1, 2, 4] , the partial-scale frequency converter is connected between the induction generator's rotor and the external grid. Operation of a DFIG during a voltage dip caused by a fault requires coordinated operation of the rotor- and grid-side converters as well as the induction generator. Additionally, due to two sudden changes in terminal voltage directly at the time of fault and fault removal, the induction generator undergoes two significant changes in output current, resulting in rotor-side overcurrents to sustain the flux linkages. To protect the rotor-side converter from these overcurrents, a DFIG is normally equipped with an additional crowbar circuit. During a voltage dip, the additional crowbar resistor will be connected into the DFIG's rotor circuit to limit the overcurrents and the rotor-side converter will be temporarily blocked for the fault duration. Although the crowbar solution can guarantee successful fault ride through, it will involve additional investment and particularly loss of control to active and reactive power outputs. Moreover, when the crowbar is activated, the DFIG will absorb a large amount of reactive power which is not allowed in some grid codes.

In contrast to a DFIG, the FSC is equipped with a full-scale frequency converter so that the operation during a voltage dip is easier to manage. The fault ride through performance is entirely determined by the characteristics of the grid-side converter, which simply adjusts its active and reactive power to comply with the fault ride through requirements. Other components, such as the generator and generator-side converter are effectively removed from service temporarily to maintain the wind turbine generator in a safe state [1, 2, 4, 12-16]. During normal operation a FSC produces active power and regulates a.c. terminal voltage [1, 2, 4, 17]. When a voltage dip occurs, the input wind power remains effectively constant, since it is determined by the wind conditions and the pitch angle, both of which change slowly relative to the fault condition. For a three-phase fault at the a.c. terminals of the FSC, the power output drops to zero. The generator-side converter adjusts its frequency to stop collecting power from the generator, causing an acceleration of the shaft that is limited by the rotor and shaft inertia. As the shaft speed increases, the rotor's pitch control adjusts to temporarily reject additional power input from the rotor. This is done very quickly (in approximately 2 seconds) by the wind turbine generator's pitch-angle controllers. When the FSC detects a voltage dip, the converter transfers to another operation mode where the priority is voltage support rather than power production. This allows the converter to provide voltage support during the fault by injecting reactive current as a function of retained voltage. As a result, compared with a DFIG, the control design of the FSC provides an effective method for providing fault ride through capability, with minimal risk to components of FSC and maximal support for the external grid.

A.4. Protection of wind turbines against loss of connection

Provision must be made to manage excess power in the event that the power generated cannot be transmitted, due to loss of a transmission connection or otherwise. Excess power will cause rotor a.c. overcurrent in the generators, over-speed of the wind turbines and d.c. overvoltages or currents in their frequency converters. Protection strategies for the wind turbine generators against such risks are required.

A.4.1. Protection strategies of DFIG

A protection scheme which has been proposed for the DFIG is shown in Figure A7 [12]. The protection scheme is a combination of four functional blocks:

- Crowbar protection
- AC series dynamic resistor

- DC chopper
- Pitch-angle control

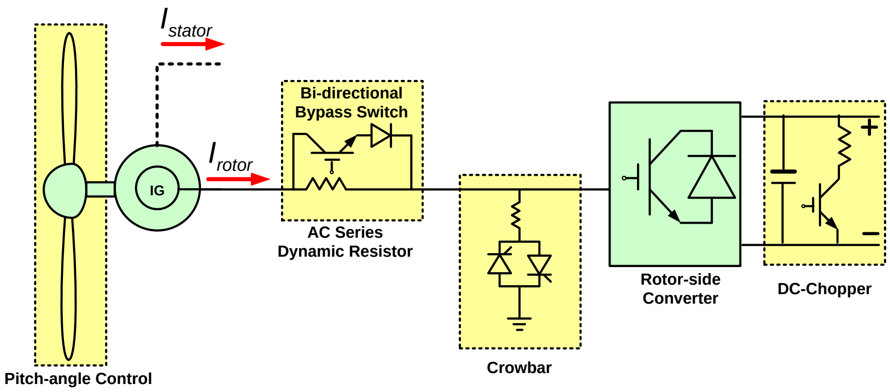

Figure A7: Protection schemes of WT-DFIG rotor-side converter

A.4.1.1. Crowbar

The crowbar protection is a prevalent protection scheme for DFIGs [1, 12, 13]. A crowbar is a set of resistors which are connected in parallel with the rotor winding in the event of an interruption, bypassing the rotor-side converter. The active crowbar control scheme connects the crowbar resistance when necessary and disconnects it to resume DFIG control. For active crowbar control schemes, the control signals are activated by the rotor-side converter. The DC-link bus voltage may increase rapidly under these conditions, so it is also used as a monitored variable for crowbar triggering. Power electronics elements e.g. bi-directional thyristors, GTOs or IGBTs are typically used for crowbar switching.

A.4.1.2. DC chopper

In [12], a DC-chopper is connected in parallel with the DC-link capacitor to limit the overcharge during low grid voltage. It protects the rotor-side converter from overvoltage and can dissipate surplus wind energy, but this has no effect on the rotor overcurrent.

A.4.1.3. AC series dynamic resistor

In [12], a new protection scheme based on a a.c. series dynamic resistor is proposed which also combines and coordinates the existing crowbar and d.c. chopper protection to absorb the surplus wind energy together. A series dynamic resistor is used as the primary protection. When the series dynamic resistor cannot protect because of a deteriorating situation, the crowbar circuit will be activated. The crowbar is engaged only at the beginning or the end of the fault, if required. The d.c. chopper is used for DC-link overvoltage limitation.

A.4.1.4. Pitch-angle control

The surplus wind energy will cause the acceleration of rotor rotational speed. To avoid over-speed, the pitch-angle control is activated. The pitch angle control reduces the rotor speed by increasing the pitch-angle of the blades to reduce the aerodynamic torque. Mechanical braking is usually used to hold the turbine still and will be used as a backup for the pitch-angle control. Since the pitch-angle of the blades is mechanically controlled, its response time is much slower than other methods based on power electronics (25% of power reduction per second or less). It is usually used as the backup method if electrical damping is not adequate in some severe fault conditions.

A.4.2. Protection strategies of FSC

A protection which has been proposed for the FSC is shown in Figure A8 [12]. The protection scheme is a combination of five functional blocks:

- AC series dynamic resistor
- AC damping load
- DC chopper
- DC series dynamic resistor
- Pitch-angle control

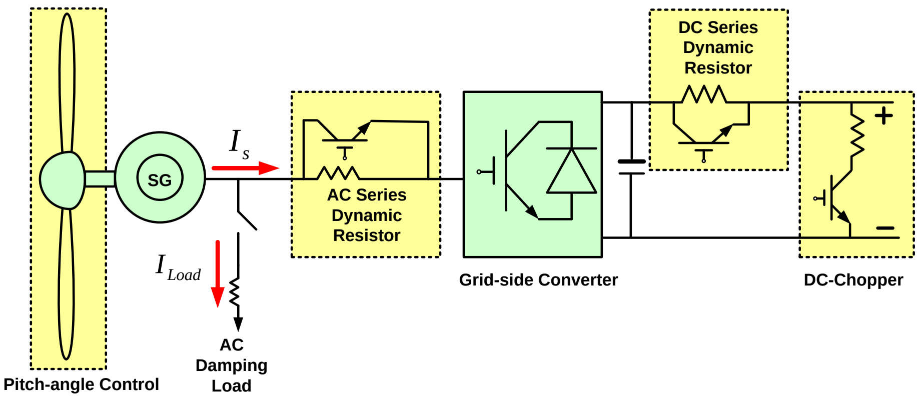

Figure A8: Protection schemes of WT-FSC grid-side converter

A.4.2.1. AC Series Dynamic Resistor

A power-electronic-controlled external resistor, which is connected to the stator windings of the generator, is used to limit the rotor overcurrent during a fault. This is a three-phase series resistor. The purpose of the a.c. series resistor is to balance the active power then improve generator stability during a fault.

A.4.2.2. AC damping load

A three-phase a.c. damping load is connected at the generator terminal to help absorb the surplus power generated by the wind turbine generator as an electrical braking system [12].

A.4.2.3. DC series dynamic resistor

A d.c. series dynamic resistor can also be used as an overcurrent limiter in the DC-link circuit. A fast solid-state switch is used to bypass or engage the resistor during normal operation and fault conditions.

A.4.2.4. DC-chopper and pitch-angle control

Application of the d.c. chopper and the pitch angle control are similar to that described in Section A.4.1.2 and A.4.1.4.

A.5. Voltage and reactive power support

Variable-speed wind turbine generators have extended capabilities to supply ancillary services including power factor regulation, dynamic voltage control and reactive power support. As a result, requirements for ancillary services for wind farms may be specified in the same way as for conventional generators [18].

A.5.1. Solutions

The voltage and reactive power capabilities of a wind farm depends on the combination of WTGs and additional reactive power compensation devices such as passive reactors/ capacitors or state-of-the-art FACTS-based SVC or STATCOM [18].

A.5.1.1. Reactive capability of wind turbines

The VSC-based frequency converter of the variable-speed wind turbine generators can achieve independent control of active and reactive power (four-quadrant operation) [1, 3]. The maximum reactive power (generation or absorption) is dependent on the power rating of frequency converter. Consequently, the reactive power capability of DFIGs is limited compared with FSCs.

DFIGs with a crowbar protection scheme have to absorb reactive power during fault ride through. However FSCs can inject reactive power into the grid with voltage support.

A.5.1.2. Passive reactive compensation devices

Mechanically-switched shunt capacitor banks typically consist of a group of individual capacitor units. The bank may either be fixed or switched using appropriately rated devices. It is only possible to control slow variations in reactive power. The capacitive reactive power output is a function of the system voltage. By using a number of capacitor banks of different size, the reactive power exchange can be kept within a range. Capacitor banks typically require a 5 minute discharge time before they can be re-energised, but there are also designs that allow for shorter durations on a limited basis.

Reactors are typically mechanically switched devices so that it is only possible to control slow variations in reactive power as well. The inductive reactive power output is a function of the system voltage. Regulated shunt reactors are shunt reactors equipped with a tap-changer as used for voltage control [18].

A.5.1.3. FACTS-based dynamic compensators

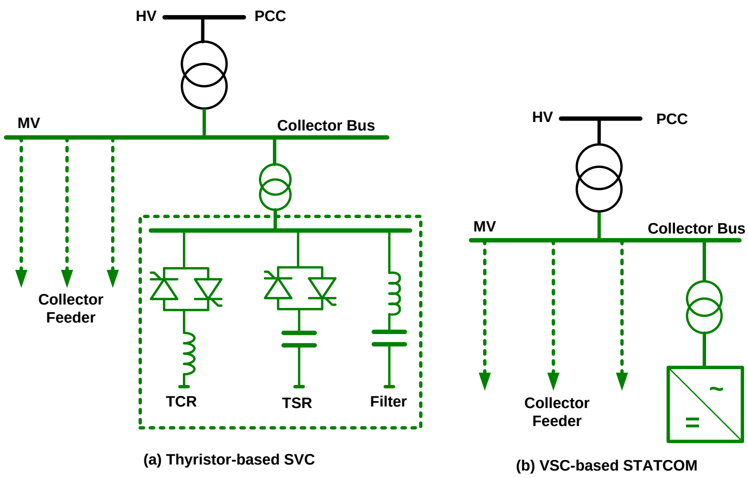

Figure A9: FACTS-based dynamic reactive compensation devices

A static VAr compensator (SVC) is typically a fixed shunt capacitance in parallel with reactance that is controlled by thyristors as shown in Figure A9(a) [18]. With dynamic control of the thyristors, reactive power may be controlled at time scales down to the order of a 100 milliseconds. Additional filters must be used to control harmonics generated by the distorted current waveshape caused by the thyristor switching. A static synchronous compensator (STATCOM), shown in Figure A9(b) [18], uses an IGBT or GTO-based voltage-source converter to generate or absorb reactive power via a fast-response control system. Some STATCOM units may have short-time overload capabilities for 2 to 4 seconds. The reactive power output is a linear function of the voltage [19].

A.6. Harmonic resonance of offshore wind farms

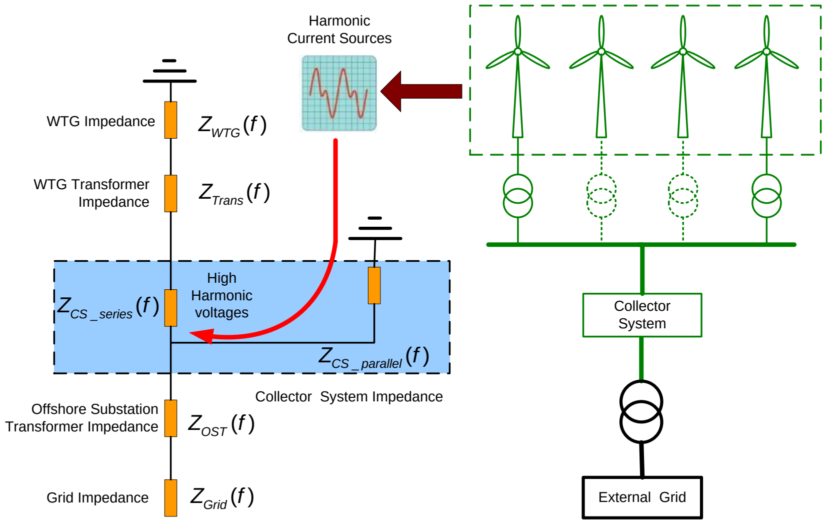

Figure A10: Harmonic generation by offshore wind farms

Harmonic resonance issues arise in offshore wind farms because they contain both inductive source and capacitive elements. The offshore wind farms typically have extensive cable systems, which can result in many series and parallel resonance points. Harmonic sources may include wind turbine generators with VSC-based frequency converters. Parallel resonance occurs when harmonic current sources excite resonant points (relatively high impedances) resulting in harmonic voltages [20-22].

A.6.1. Requirements

The offshore wind farms and interconnection facilities for the offshore wind farms e.g. HVDC links should be designed to avoid introducing detrimental harmonic resonance into the transmission system. The design of the wind farm protection and control schemes shall ensure that any issues related to resonance are addressed.

A.6.2. Solutions

There are two primary methods for controlling harmonic impact in wind power plants [20]: Harmonics may be controlled during the design of the wind plant collector system by careful consideration of equipment to avoid resonance problems; alternatively, harmonic filters may be designed based on measurements and simulation results in order to reduce or control series resonance conditions of the wind plant. The latter method is the most common mitigation approach when capacitive compensation is required.

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9. CONCLUSIONS

The report has aimed to establish the present state of development of the technologies required for an integrated offshore transmission system and to identify developments required in order for an integrated offshore transmission system to be built. A brief introduction to the technologies, including HVDC converters, switchgear, cables and offshore platforms, has been provided and the application issues highlighted.

Differences in the characteristics of line commutated converter (LCC) and voltage sourced converter (VSC) HVDC technologies may lead to one or the other being better suited to the functional requirements of a project. VSC HVDC converters are well suited to connection of offshore wind generation and to multi-terminal applications as required for the integrated offshore transmission project. The use of LCC technology for wind generation and offshore applications would generally require additional investment and would present some additional engineering challenges. The possibility of commutation failures affecting more than one inverter on the onshore transmission system would need to be excluded.

LCC HVDC converters are a mature technology and comprehensively covered by international standards. Standards have been developed for many aspects of VSC HVDC converters. CIGRE is currently preparing guidance on commissioning. At present, there is no standard for insulation coordination for VSC HVDC converters.

Many of the technologies required for an integrated offshore transmission network are new and developing rapidly. The report has attempted to anticipate how these technologies might continue to develop and provide an indication of technology availability by year.

VSC HVDC systems with extruded cable are under construction with power transfer capabilities of 1000 MW. The technology exists to allow 1400 MW to be achieved. It is envisaged that 2000 MW VSC HVDC systems could be in service by 2019 with mass impregnated cables and, with some development in converter valve technology to increase d.c. current, by 2021 with extruded cables.

VSC HVDC converters for offshore application are under construction at +/- 320 kV, allowing power transfer capabilities of around 1000 MW to be achieved. Several projects with offshore converters are currently in progress and valuable experience will be gained from these. There is a clear requirement for reducing the costs of platforms for offshore HVDC converters. It is thought that developments in offshore platform technology would allow a 2000 MW offshore converter to be in service by 2021.

An LCC HVDC system with mass impregnated cables with a power transfer capability of 2250 MW is due to be in service during 2016. The power transfer capability of LCC HVDC systems is governed by the d.c. voltage and current of the cable. Beyond 2016, the capability of VSC HVDC converters is foreseen to have also reached that of the cable. From then on, LCC HVDC systems with cables will no longer offer a greater power transfer capability than VSC HVDC systems.

The first two multi-terminal VSC HVDC systems have recently been commissioned. Both were designed and built as multi-terminal systems in a single stage of construction. To facilitate the wider implementation of multi-terminal HVDC systems, the development of standards to ensure compatibility of the equipment of different suppliers on a common HVDC system is highly desirable. Working Bodies within CIGRE and CENELEC are currently active in this area.

An HVDC circuit-breaker has been demonstrated in the laboratory. It is expected that such a device could be in service by 2019. Ongoing developments are envisaged in HVDC circuit-breaker technology in pursuit of increased operating speeds, higher ratings, reduced losses and reduced costs.

Unit costs have been obtained for each of the technologies required for an integrated offshore transmission network for use in cost benefit analyses. Obtaining the costs has proved difficult. Costs are influenced by many factors, including the specific requirements of a given project, exchange rates, commodity prices and the balance of supply and demand in the market at the time of tender. Due to a scarcity of current data, the costs were generally obtained by inflating those published in National Grid's 2011 Offshore Development Information statement in line with the Harmonised Index of Consumer Prices (HCIP).

In order to be able to make use of commodity prices in unit costing, research is needed into the relative quantities of materials in each of the units, particularly for VSC HVDC converters and offshore HVDC converter platforms. Research is also required into the construction and costs associated with offshore HVDC converter platforms.

Information on reliability and availability of HVDC technology has been collected for use in cost benefit analyses. Data for HVDC converters has been obtained from annual surveys reported by CIGRE AG B4.04. All of the reported data was for LCC HVDC schemes, since experience with VSC HVDC schemes is still limited. In the absence of data for VSC HVDC converters, it is assumed that the values reported for LCC HVDC schemes could be used given the similarities in the technologies.

Reliability and availability data for d.c. cables has been obtained from a survey performed by CIGRE WG B1.10. The survey included data for d.c. mass impregnated cables but not d.c. extruded cables. In the absence of data for d.c. extruded cables, it is assumed that the values reported for d.c. mass impregnated cables could be used since none of the reported failures were attributed to internal causes and are therefore unlikely to be related to the type of insulation.

There is a clear need to collect and publish data on the reliability and availability of VSC HVDC converters and extruded d.c. cables.

Established specifications exist for the protection systems of converter stations connected to the onshore a.c. network. In this report, protection strategies have been illustrated for a number of generic scenarios representing the basic types of connection of which an integrated offshore network is formed.

In an integrated network where HVDC links are interconnected by offshore a.c. networks, a d.c. fault may be cleared by the a.c. circuit-breaker at each terminal of the affected HVDC link. This represents a viable solution to the design of an integrated offshore transmission network. The network may be designed such that the limits on loss of infeed permitted by planning standards are not exceeded.

In a multi-terminal HVDC system, the disadvantage of clearing a d.c. fault by a.c. circuit-breakers is that the whole multi-terminal system will be tripped. The commercial availability of the HVDC circuit-breaker will allow a d.c. fault in a multi-terminal HVDC system to be cleared while the unaffected branches of the system remain in operation. The HVDC circuit-breaker will therefore facilitate the application of larger multi-terminal HVDC systems.

CIGRE WG B4/B5.59 has been developing guidelines for control and protection of HVDC grids, with emphasis on protection of the grid and the elements in it. Their report is expected to be published shortly.

The report has illustrated the principles of primary and secondary control in an integrated offshore transmission network. Primary control is reasonably well understood and strategies can be proposed for achieving the required steady state power flows through HVDC links and the offshore network. A converter can respond to changes in the a.c. or d.c. networks by means of its pre-programmed control characteristics. The control characteristics of the converters in a system can be coordinated such that the system can respond to events such as loss of a transmission connection and reach a new steady state operating condition without dependence on telecommunications. Secondary control can than be used to change converter control characteristics to establish a new optimum power flow.

Coordination of control to achieve the required power flows has been illustrated using the same generic scenarios as previously. In general, a feasible solution can be proposed for each scenario. At least one converter of each HVDC link must control the link d.c. voltage. The frequency of the a.c. offshore network may be used to control the power through the HVDC links and the offshore network. Challenges may be encountered, however, where a converter connected to an offshore a.c. network is used to control the d.c. voltage of a d.c. link since it will not automatically respond to changes in the a.c. network.

The discussion in the report has concentrated on steady state power flow. Studies are required to simulate the dynamic response of an integrated offshore network in order to investigate issues including the stability of the a.c. and HVDC systems and any transient overloads. It also needs to be established whether it is feasible to change the control mode of a converter so that it can take over frequency control of an offshore a.c. network in the event that another converter trips.

Where offshore wind farms are connected by a.c. connections, it becomes increasingly important that the generators remain transiently stable and connected in the event of a short circuit fault in the offshore a.c. network. Due to the exclusive use of wind turbine generators and cable connections, the conditions in the offshore a.c. network in the event of a fault may be more onerous than those covered by the fault ride through requirements of existing grid codes. The range of conditions existing in the event of a short circuit fault in the offshore a.c. network requires to be established and, if necessary, appropriate fault ride through requirements developed to address the more onerous conditions.

In an integrated network, provision must be made to manage the situation where the total generation in an offshore a.c. network exceeds the capacity of the remaining transmission connections when one of the connections is lost. Urgent action is required to prevent the remaining connections from overloading and tripping in cascade. The effectiveness of any method used to prevent overloading and cascade tripping is dependent on its ability to operate within the short timescales involved.

In principle, it would be possible to reduce power generation by control action, possibly using the frequency of the offshore network as a trigger. The use of a power reduction controller has been proposed in the literature. It was stated that, due to the fast response of the wind turbine converters, the output power is reduced quickly.

A semiconductor-controlled resistor bank (‘ac chopper’) connected to the offshore network could be provided to dissipate the excess power. Such a device would be able to operate sufficiently rapidly but would represent a significant additional investment.

Excess power generation may be reduced by tripping generators, but the time required for decision plus circuit-breaker operation may be too long.

Wind turbine blade pitch control reduces power generation typically over a period of seconds and is therefore not fast enough to be effective in preventing overload and cascade tripping. It may, however, reduce the period of time for which an alternative method of managing excess power generation is required to be active.

Detailed studies are required to simulate the sequence of events occurring when a connection is lost and to evaluate potential solutions to prevent overloading and cascade tripping. It will be necessary to understand the rate of change of frequency and voltage in the offshore a.c. network following loss of a connection and the timescales for control- and protection-initiated actions. If the need for a.c. resistor banks to dissipate excess generated energy is confirmed, the functional requirements and cost of such equipment will need to be determined. The development of new converter topologies having greater overload capability would alleviate the problem.

The risk of overloading and cascade tripping does not arise if the total generation is within the capacity of the remaining connections when the largest connection is lost.

The extensive cable systems of the offshore a.c. networks will potentially present a large range of harmonic resonant frequencies. It may be possible to manage harmonic generation through careful equipment design or through the provision of a.c. harmonic filters. It must be ensured that there is no adverse interaction with the control systems of converters. A generic understanding of the potential issues would be helpful but it will be essential to demonstrate satisfactory operation of the converter and a.c. network for any given project. This may best be achieved by simulation during factory testing.

VSC HVDC schemes may be constructed in stages to better match investment with system requirements where the potential requirement for a higher transmission capacity it some point in the future is anticipated. Staged construction has been described in the report. The initial scheme is constructed as an asymmetrical monopole, which is extended to form a bipole in a second stage of construction. The installation of a third d.c. circuit conductor will allow one of the original d.c. circuit conductors to be used as a metallic return. The provision of a metallic return, while increasing the cost of the second stage of construction, will improve availability, particularly in the event of an outage of a d.c. circuit conductor, and will limit the loss of transmission in the event of a fault or converter trip. Staged construction might be a viable approach in the construction of an integrated offshore transmission system.